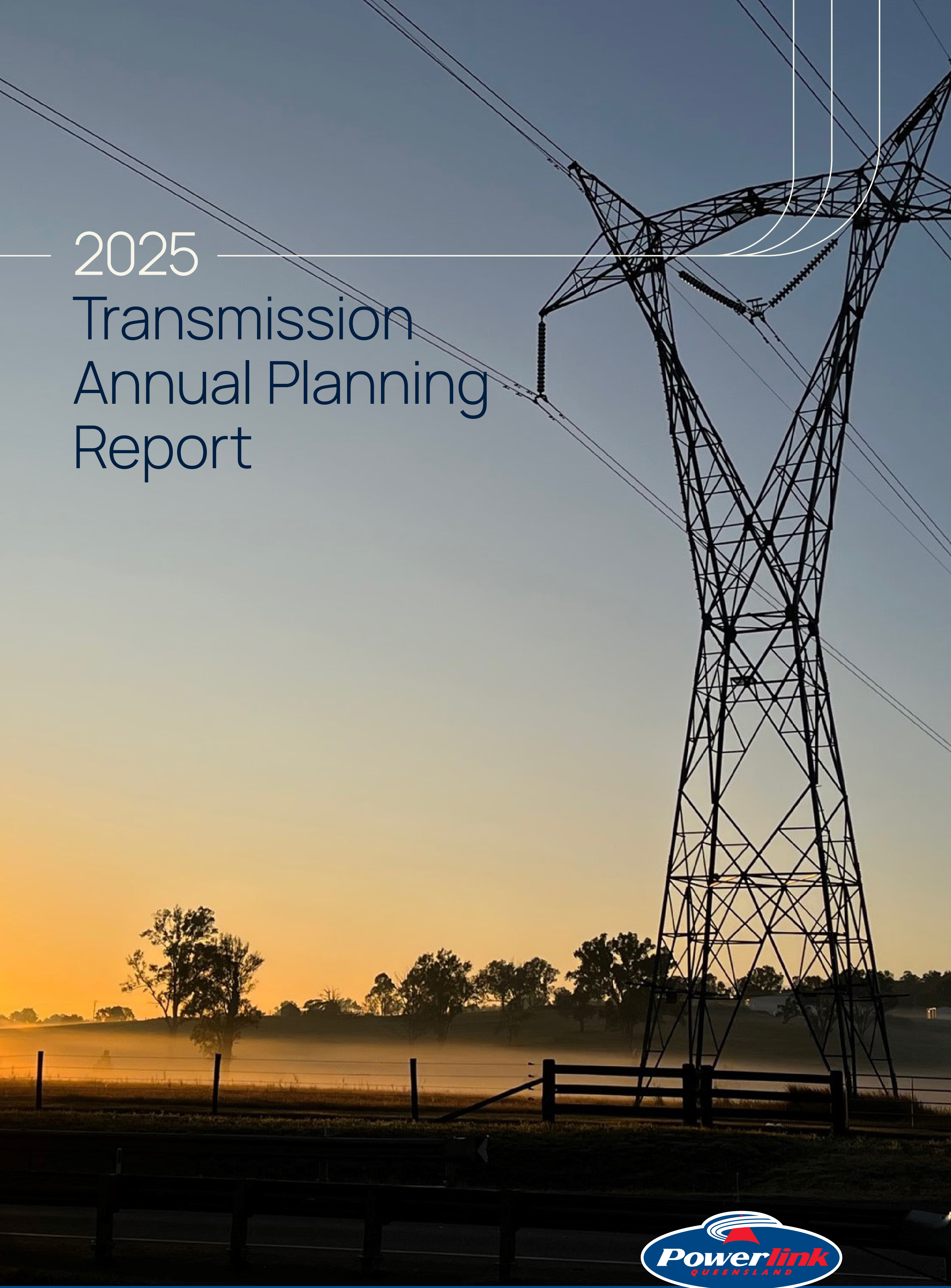
Powerlink 2027-32 Revenue Proposal

Appendix 4.02

2025 Transmission Annual Planning Report

2025 Transmission Annual Planning Report



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Acknowledgement of Country

Powerlink acknowledges the Traditional Owners and their custodianship of the lands and waters of Queensland and in particular, the lands on which we operate. We pay our respect to their Ancestors, Elders and knowledge holders and recognise their deep history and ongoing connection to Country.

Foreword

Powerlink is dedicated to connecting Queenslanders to a world-class energy future by delivering safe, reliable, and cost-effective electricity services to our customers. As the energy market and customer expectations continue to evolve at pace, our Transmission Annual Planning Report (TAPR) remains central to our ongoing role in guiding the market in Queensland.

Navigating complexity and cost

Queensland's transmission system is facing increasing complexity:

- The integration of new generation and storage projects is accelerating.
- Large load customers are considering their long-term energy needs.
- The continued growth in rooftop solar photovoltaic (PV) is reducing minimum demand, even as maximum demand continues to increase.

A key part of our response to this complexity, our Next Generation Network Operations (NGNO) program, delivered a major milestone this year with the modernisation of our real-time control room facility, improving our operational capability.

As Queensland's System Strength Service Provider, Powerlink completed a Regulatory Investment Test for Transmission (RIT-T) in June 2025, targeting system strength requirements for the short to medium term. We have commenced procurement of both network and non-network solutions to meet these needs.

Local and global demand for resources that are essential for transmission projects continues to put upward pressure on costs and extend equipment delivery timeframes.

To mitigate these pressures, Powerlink has:

- developed alternative supply options for critical equipment such as 275 kilovolt circuit breakers
- implemented alternative strategies to transmission line refits works to capture scale
- continued to refine transmission augmentations to drive value for customers.

Engaging with customers and communities

Powerlink is committed to effective engagement with customers, communities, First Nations Peoples and other stakeholders to share information and use feedback received to improve decision making.

Given transmission network infrastructure is typically in service for over 50 years, Powerlink is committed to fostering positive relationships and partnering with local communities to deliver lasting benefits.

In 2025, we refreshed our Community Engagement Approach to continue driving best-practice engagement and generating lasting benefits for communities.

By strengthening and increasing the capacity of our transmission network, Powerlink is ensuring a resilient supply of electricity to deliver wider economic benefits, meet future industrial energy needs and attract new businesses to Queensland.

Queensland Government's Energy Roadmap

Our planning and investment decisions are guided by the Queensland Government's Energy Roadmap, released on 10 October 2025. The Energy Roadmap sets clear priorities for an affordable, reliable and sustainable energy future. Frameworks such as the Priority Transmission Investment framework and Regional Energy Hubs support us to deliver targeted, efficient network investments that maintain system security, support regional growth, and deliver value for customers.

We are committed to a pragmatic, whole-of-system approach that ensures every investment supports Queensland's evolving requirements. Our 2025 TAPR demonstrates this alignment in practice, with strategic projects and transmission augmentations shaped by the Energy Roadmap's priorities—including relieving congestion, better utilising existing infrastructure, and supporting the state's future energy needs.

Central Queensland: a strategic priority

The Central Queensland region is critical to Queensland's energy and economic landscape. In 2024/25, Powerlink advanced the Gladstone Project that will deliver essential network upgrades and reinforcements to maintain system security and reliability in the region. The timing of the Gladstone Project aligns with the recent notification of Gladstone Power Station's potential retirement in March 2029. A final assessment report was published in June, and the Energy Roadmap recognises the Gladstone Project as a critical transmission project for the 2025 to 2030 period. This work reflects our commitment to supporting regional communities and ensuring the transmission network evolves in step with Queensland's energy future.

Growing connections pipeline

Interest in new transmission network connections continues to grow. Powerlink has completed connection of 34 large-scale solar, wind farm and battery energy storage system projects in Queensland, adding 6,736 megawatts (MW) of generation and storage capacity to the grid since 2017.

A further 42,368MW of connection enquiries and applications for new generation and storage capacity have been received and are at varying stages of progress. Managing this scale of demand requires careful planning, streamlined processes, and ongoing engagement with proponents to ensure timely, cost-effective delivery of new connections that meet customer and market needs.

Looking Ahead

Powerlink's approach to asset management, investment planning and timing is driven on a principle of prudent investment and innovation to prepare Queensland's network for the opportunities and challenges ahead.

We have worked closely with the Queensland Government on its Energy Roadmap, which outlines the state's future energy priorities and pathways.

These priorities inform our approach to transmission augmentations and line refit programs. We are also actively engaging with the Australian Energy Market Operator on the draft 2026 Integrated System Plan, due for release in December 2025. As policy and market signals evolve, we will continue to refine our investments to deliver safe, reliable and cost-effective transmission services for our customers.

We remain focused on building a resilient, future ready transmission network that supports Queensland's energy transition and delivers lasting value for our customers, communities, and the state.

Dr Stewart Bell
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Operations and Planning Division
Powerlink Queensland

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Network Investment Division
Powerlink Queensland

Table of contents

Contents

Contents

Contents

Executive Summary

Introduction

Powerlink Queensland owns, develops, operates and maintains Queensland's high voltage electricity transmission network. The network extends from Cairns to the New South Wales (NSW) border and comprises 15,559 circuit kilometres (km) of lines and 154 substations, and provides electricity to more than five million Queenslanders and 241,000 businesses.

Powerlink connects large generators to end-use customers through the distribution networks owned by Energex and Ergon Energy (part of the Energy Queensland Group), and Essential Energy (in northern NSW), and provides electricity directly to large industrial customers such as rail companies, mines and mineral processing facilities.

About the Transmission Annual Planning Report

Powerlink undertakes an annual planning review in accordance with the requirements of the National Electricity Rules (NER) and publishes the findings of this review in the Transmission Annual Planning Report (TAPR) and associated templates available in the TAPR Portal.

Powerlink's TAPR remains central to our role in guiding the market in Queensland, providing customers, communities and other stakeholders with an overview of Powerlink's planning processes and decision making on future investment.

Focusing on delivering benefits to Queenslanders through timely network investments

Powerlink's approach to long-term network planning continues to:

- ensure investment decisions deliver positive outcomes for customers
- focus on developing options that deliver safe, reliable and cost-effective transmission services
- undertake community, customer and stakeholder engagement to inform our decision making and planning for transmission and related developments
- emphasise an integrated, flexible and holistic analysis of future investment needs
- support diverse generation connections and technologies
- adapt to changes in customer behaviour and the economic outlook
- ensure compliance with legislation, regulations and operating standards.

Network connections

Interest in new transmission network connections in Queensland continues to grow. Since 2017, Powerlink has completed the connection of 34 large-scale solar, wind farm and Battery Energy Storage System (BESS) projects in Queensland, adding 6,736 megawatts (MW) of generation capacity to the grid. A significant number of formal connection applications, totalling 42,368MW of new generation and storage capacity, have been received and are at varying stages of progress.

Storage is essential to smooth out variations in supply from variable renewable energy (VRE) generation. Prior to 2022, Wivenhoe Pumped Storage Hydro Power Station was the only transmission-connected energy storage in Queensland. Since then, seven grid-connected batteries have come online or are in commissioning. The Punchs Creek Solar Farm in southern Queensland recently became the first committed solar generation project to incorporate battery storage to connect to the Powerlink network.

Engaging with customers and communities

Powerlink is committed to effective engagement with customers, communities, First Nations Peoples and other stakeholders to share information on activities and use feedback to improve decision making.

Transmission infrastructure typically stays in-service for over 50 years and Powerlink acknowledges the potential impacts long-life assets may bring to those who live and work near our infrastructure. Powerlink is focused on building positive relationships and partnering with local communities to deliver benefits for the longer term. First developed in 2021, the Community Engagement Approach was refreshed in 2025 to continue driving best-practice engagement and generating lasting benefits for communities.

Powerlink hosts a Customer Panel that provides an interactive forum for stakeholders and customers to give input and feedback to Powerlink regarding decision making, processes and methodologies. The panel comprises members from a range of sectors including industry associations, community advocacy groups, directly connected customers and distribution representatives. It also provides an important channel for Powerlink to keep stakeholders informed about operational and strategic topics of relevance and, most importantly, provides an avenue for their insights on particular activities. The panel met in September 2024, and in April and July 2025, to consider key topics of interest. Members of the Customer Panel also offered their time to be part of Powerlink's new Revenue Proposal Reference Group, as well as an expert panel on the Gladstone Project Priority Transmission Investment (PTI).

Energy and demand projections

Based on Powerlink's Central scenario forecast of future load, Queensland's:

- transmission delivered maximum demand is expected to have steady growth with an average annual increase of 2.2% per annum over the next 10 years, mainly due to industries beginning to electrify their operations and new anticipated loads
- transmission delivered minimum demand is expected to steadily decrease with an average annual decrease of 6.3% per annum over the next 10 years, mainly due to the continued installation of residential rooftop solar photovoltaic (PV) systems.

Compared to last year's TAPR, Powerlink forecasts a slower decline in minimum demand across the 10-year outlook period due to:

- the rising adoption of residential batteries introducing new charging loads during traditionally low-demand periods
- a more moderate projection of rooftop solar PV uptake and the decommissioning of old rooftop solar systems.

The adoption of rooftop solar PV and distribution-connected solar PV non-scheduled systems continues to reduce daytime electricity demand across the transmission network. Queensland set a new record for minimum transmission delivered demand of 2,240MW, at 11:30am on Sunday, 31 August 2025. Mild weather conditions, on a weekend, and strong contribution from rooftop solar PV contributed to this new record, which was 298MW lower than the previous record minimum set in October 2024.

Queensland also set a new maximum transmission delivered demand of 9,974MW at 6:00pm on Wednesday, 22 January 2025. This maximum demand was 545MW greater than the previous record set in January 2024.

Powerlink has not included specific data centre projects into the Central scenario demand forecast for Queensland at this time. Powerlink will continue to monitor developments and adjust future forecasts accordingly. Powerlink's forecast for electric vehicle uptake remains largely consistent with the 2024 TAPR values. Last year's projection estimated around 59,000 electric vehicles, while registrations as of January 2025 reached approximately 63,000. The future charging behaviour of electric vehicle owners is a key source of forecasting uncertainty. If charging is unmanaged, owners might charge during peak evening hours and add strain to the grid, whereas smart charging via time-of-use tariffs will move charging away from evening peaks.

System security services

Queensland's power system has historically comprised of synchronous generation such as coal-fired power stations, gas turbines and hydro-electric plants. These large generators inherently provide various system security services, such as voltage regulation, inertia and system strength. The increased contribution of inverter-based generation sources, particularly solar and wind, can reduce the availability of system security services, prompting the need for new approaches to the planning and delivery of these services in the National Electricity Market (NEM).

The Australian Energy Market Operator (AEMO) has responsibility for the forecasting of power system security services. AEMO's annual system security reports assess the need for services across all regions of the NEM, and evaluate requirements for system strength, inertia and Network Support and Control Ancillary Services (NSCAS). Powerlink is required to procure services to meet the needs in its capacity as System Strength Service Provider, Inertia Service Provider, and Transmission Network Service Provider respectively.

Powerlink recognises that uncertainties in investing in system security services cannot be resolved through analysis alone, as they depend on factors that are either confidential to market participants or subject to future conditions that are inherently uncertain and evolving.

Powerlink's strategy to meet our responsibilities to plan for and make system security services available includes:

- pursuing a complementary mix of different technologies to address requirements
- timing the investment in solutions to anticipate withdrawal of generation, while preserving flexibility to invest in and procure further solutions over time
- working with the Queensland Government and Energy Queensland to explore ways to enhance Queensland's operational tools to maintain system security during periods of low operational demand.

Powerlink completed a Regulatory Investment Test for Transmission (RIT-T) in June 2025 to address system strength requirements for the short to medium term. Procurement of both network and non-network solutions to meet these needs has commenced. Powerlink has also entered into a System Strength Services Agreement with the owner of the Townsville Power Station in Northern Queensland to enable modifications to allow the facility to operate in synchronous condenser mode and provide system strength services.

Future network investments

Powerlink's regulated capital expenditure program of work will continue to focus on risks arising from the condition and performance of existing aged assets, as well as emerging limitations in the capability of the network.

In addition to the RIT-T for system strength, Powerlink has completed or commenced consultation processes for regulated network investment since the 2024 TAPR, including:

- issuing a joint Project Specification Consultation Report (PSCR) with Ergon Energy to address network needs in the Kamerunga, Cairns and northern beaches area
- releasing PSCRs to address the risk of premature current transformer failures in Queensland, and to maintain reliability of supply and address condition risks at Ingham South
- finalising a RIT-T to maintain reliability of supply to our Mansfield site.

Powerlink also completed an assessment, through the PTI framework, for the Gladstone Project, which aims to provide sufficient power transfer capability to reliably supply the forecast electrical load in the Gladstone area, in anticipation of the potential retirement of Gladstone Power Station and to support the initial electrification of major industries in the Gladstone area. Powerlink continues to work closely with the Queensland Government on the next phase of the project, noting their recent Energy Roadmap recognised the project as a critical transmission project for the 2025 to 2030 period.

Powerlink is also actively engaging with AEMO on the draft 2026 Integrated System Plan, due for release in December 2025.

Local and global demand for resources essential for transmission projects continues to put upward pressure on costs and extend equipment delivery timeframes. To mitigate these pressures, Powerlink has:

- developed alternative supply options for critical equipment such as 275 kilovolt (kV) circuit breakers
- implemented alternative strategies to transmission line refits works to capture scale
- continued to refine transmission augmentations to drive value for customers.

Powerlink will continue to implement changes to the timing, scope and bundling of proposed line refit works, to maximise the potential for more cost-effective solutions as recommended in the Asset Reinvestment Review, concluded in June 2023.

Powerlink is continuing with the development and roll out of the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events. WAMPAC has been implemented for system protection services across the Central Queensland to South Queensland grid section to increase the resilience and security of the network under non-credible contingencies, and will soon be in-service to manage the impacts of outages on system strength in Far North and North Queensland.

Powerlink anticipates initiating a number of RIT-T consultations in the coming year. Proponents of non-network solutions are strongly encouraged to engage in our RIT-T processes to support the selection of prudent and efficient solutions to meet emerging needs. Powerlink is committed to genuine engagement with providers of non-network solutions and the implementation of these solutions where technically feasible and economic to:

- address inertia, system strength and NSCAS requirements
- address future network limitations or address the risks arising from ageing assets remaining in-service within the transmission network
- complement network developments as part of an integrated solution to deliver an overall network strategy
- provide demand management and load balancing.

Network performance

Network capability and performance is central to ensuring the reliability and efficiency of the energy system, and for integrating new generation into the grid. Powerlink's transmission network performed strongly in 2024/25. Record maximum and minimum transmission delivered demand was recorded for the South West, Moreton, Bulli and Gold Coast zones. The Far North zone also became a net exporter of energy for the first time in 2024/25 due to continued increases in generation.

Strategic projects

Powerlink's approach to investment planning and timing is driven on a principle of prudent investment and innovation to prepare Queensland's network for the opportunities and challenges ahead. This approach enables timely responses to market signals, supports generation growth and integrates a mix of firming assets such as batteries, gas powered generation and longer duration solutions like Pumped Hydro Energy Storage (PHES).

In line with the Energy Roadmap, Powerlink is implementing a staged development model that is prudent and efficient, providing flexibility to accommodate future load growth and generation patterns. This approach focuses on:

- targeted 275kV augmentations and asset rebuilds to relieve congestion and better utilise existing infrastructure
- rebuilding ageing assets with higher capacity solutions to provide flexibility for future load growth and generation patterns
- applying staged development principles to respond efficiently to market signals and integrate firming technologies such as PHES.

Powerlink is aware of several proposals for large mining, metal processing, and other industrial loads, including the electrification of existing operations. While these developments have not progressed sufficiently to be included in Powerlink's Central scenario forecast of future load, they collectively represent approximately 2,982MW across Northern, Central and Southern Queensland and may trigger network investment to maintain reliability of supply.

Powerlink is committed to early and meaningful engagement, and continues to enhance processes for ensuring appropriate community and landholder participation in corridor selection and easement acquisition processes. Over the coming months, Powerlink will continue to shape and refine its approach to identifying priority easement activities that are needed to support the timely and socially responsible delivery of future transmission projects.

Introduction

01

01. Introduction

Powerlink's annual planning review and Transmission Annual Planning Report (TAPR) are central to ensuring the Queensland transmission network continues to meet the needs of customers and National Electricity Market (NEM) participants into the future. This chapter outlines Powerlink's planning obligations and role in Queensland's power supply industry.

Key highlights

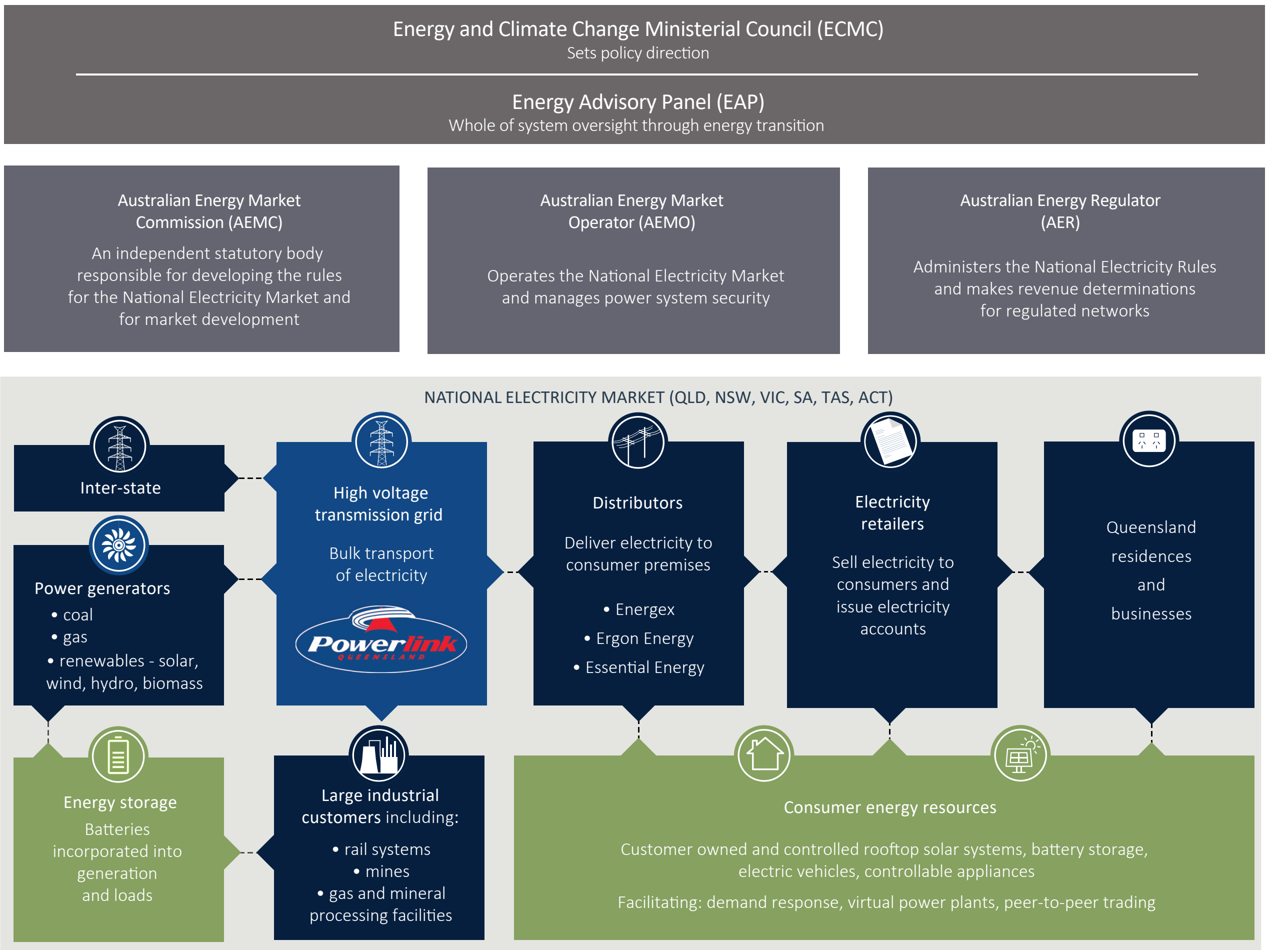
- Powerlink owns, develops, operates and maintains the high voltage electricity transmission network in Queensland, which provides electricity to more than five million Queenslanders and 241,000 businesses.
- The TAPR provides information about the Queensland transmission network, including key areas forecast to require investment in the 10-year outlook period.
- Powerlink is committed to effective, targeted engagement with customers, communities, First Nations Peoples and other stakeholders to share information on activities and use feedback received to improve decision making.

1.1 Powerlink's role in Queensland's power supply

Powerlink owns, develops, operates and maintains Queensland's high voltage electricity transmission network. The network extends from Cairns to the New South Wales (NSW) border and comprises 15,559 circuit kilometres (km) of lines and 154 substations and provides electricity to more than five million Queenslanders and 241,000 businesses.

Powerlink connects large generators to end use customers through the distribution networks owned by Energex and Ergon Energy (part of the Energy Queensland Group), and Essential Energy (in northern NSW), and provides electricity directly to large industrial customers such as rail companies, mines and mineral processing facilities.

Figure 1.1 Powerlink's role in the Queensland power supply industry



1.2 Purpose of the TAPR

The purpose of Powerlink's TAPR is to provide information about the Queensland transmission network to those interested or involved in the NEM. The TAPR also provides customers, communities and other stakeholders with an overview of Powerlink's planning processes and decision making on future investment.

Readers should note this document and supporting TAPR Templates and TAPR Portal are not intended to be relied upon explicitly for the evaluation of customer investment decisions. Interested parties are encouraged to contact Powerlink directly for more detailed information[1].

1.3 Context of the TAPR

Powerlink undertakes an annual planning review in accordance with the requirements of the National Electricity Rules (NER) and publishes the findings of this review in the TAPR, and associated templates made available in the TAPR Portal[2].

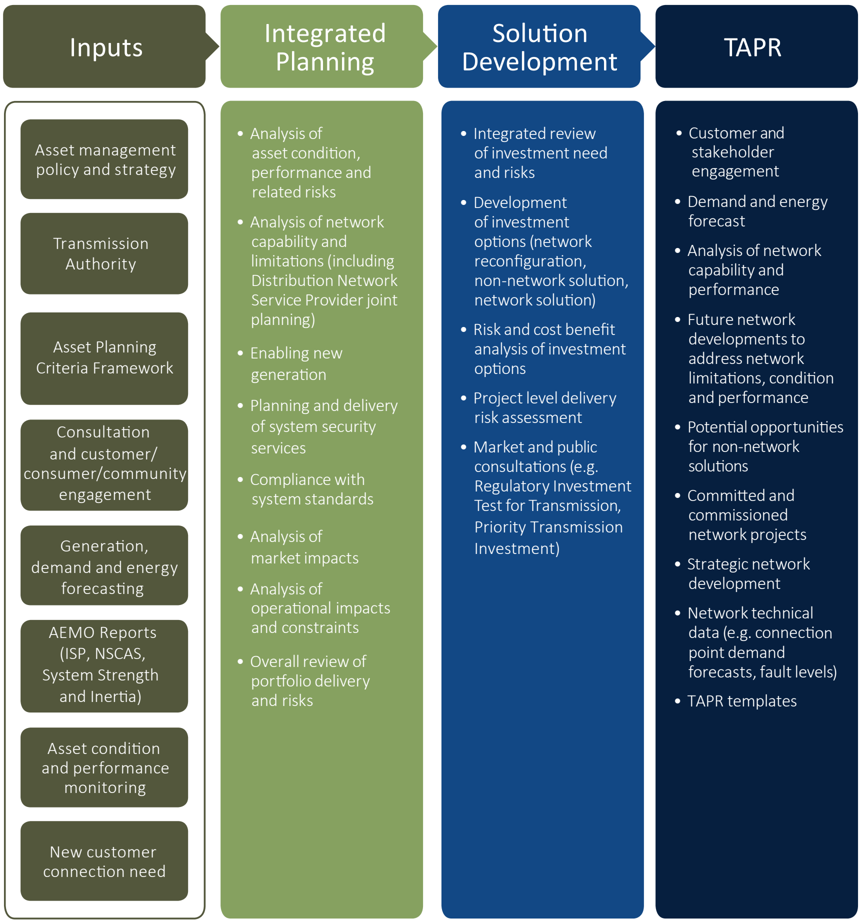
Powerlink provides information from its annual planning reviews to the Australian Energy Market Operator (AEMO) to assist in the preparation of its Integrated System Plan (ISP). The ISP sets out an essential infrastructure plan for the eastern and south-eastern seaboard's power system over the next two decades. The ISP identifies actionable and future projects requiring regulatory consultation, and informs market participants, investors, policy makers and customers about a range of potential future development opportunities.

1.4 Powerlink's planning obligations and process

1.4.1 Overview

An overview of Powerlink's TAPR planning process is presented in Figure 1.2.

Figure 1.2 Overview of Powerlink's TAPR planning process



Detail on Powerlink's planning criteria, responsibilities and processes is available in Appendix A.

[1] Unless stated otherwise, the information published in the 2025 TAPR is current as at 30 September 2025.
[2] National Electricity Rules (NER), rule 5.12. For Powerlink's 2025 TAPR, Version 231 (effective 1 July 2025) of the NER has been applied.

1.5 Overview of network connections

Interest in new transmission network connections in Queensland continues to grow.

1.5.1 Summary of connection projects

Table 1.1 provides an overview of the development of connection projects undertaken or being undertaken by Powerlink since 2017.

Table 1.1 Summary of connection projects

Projects	2025 TAPR Status	
Total completed to date	34	6,736MW
Under construction	9	2,660MW
Current connection applications	103	42,368MW

Notes:

(1) MW denotes megawatts.

(2) To date Powerlink has completed eight storage projects, totalling 3,190 megawatt hours (MWh) of energy storage and a further 4,935MWh are under construction.

1.5.2 Status of connection projects

Since 2017, Powerlink has completed connection of 34 large-scale solar, wind farm and Battery Energy Storage System (BESS) projects in Queensland, adding 6,736MW of generation capacity to the grid. A significant number of formal connection applications, totalling 42,368MW of new generation and storage capacity, have been received and are at varying stages of progress.

During 2024/25, 1,027MW[3] of semi-scheduled generation capacity has been committed in the Queensland region.

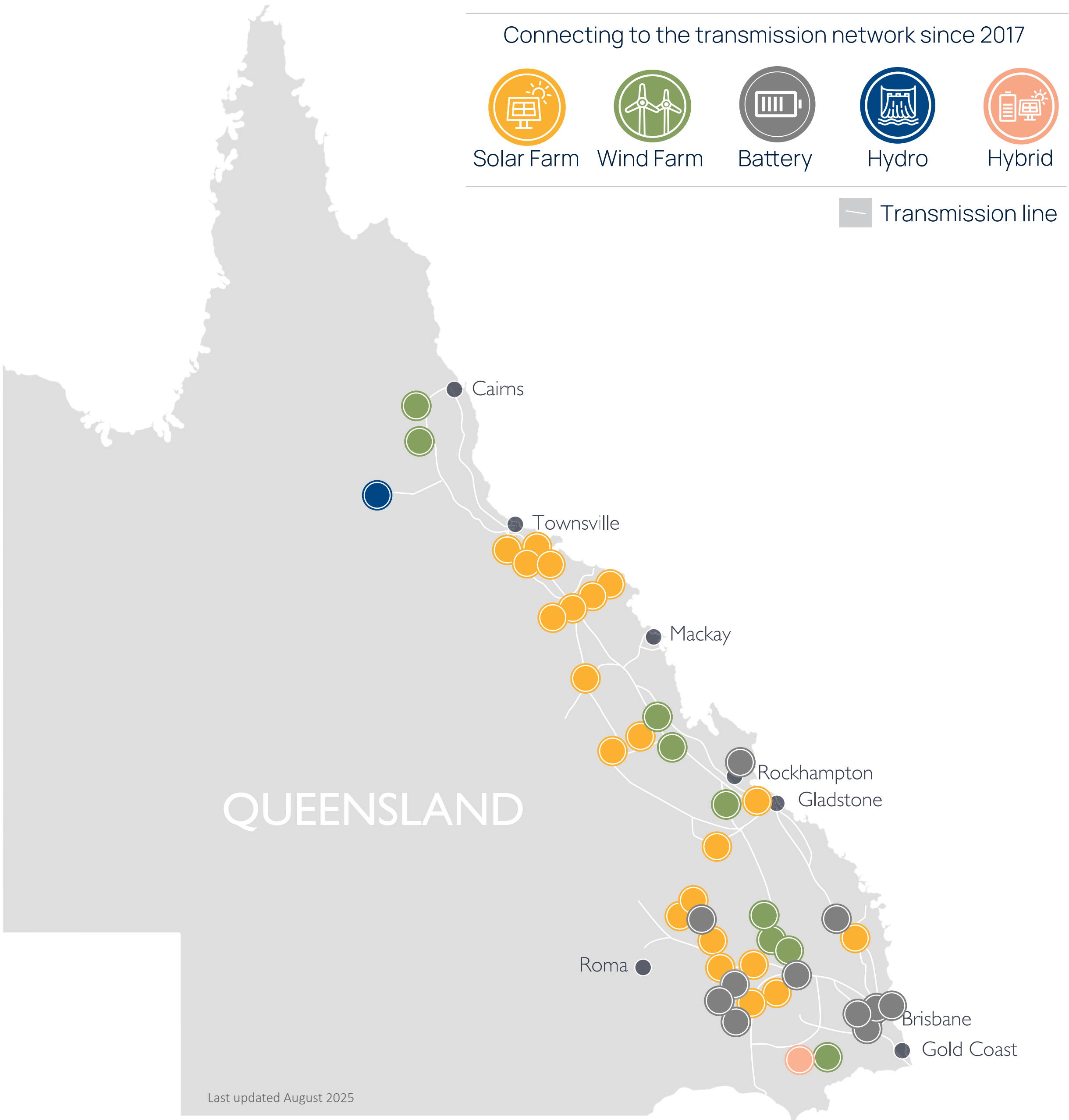
Approximately 1,494MW of embedded semi-scheduled generation projects exist or are committed to Energy Queensland's network. In addition to the large-scale generation development projects, rooftop solar photovoltaic (PV) in Queensland exceeded 7,200MW in June 2025.

Figure 1.3 shows the location and type of generators connected and committed to connect to Powerlink's network[4].

[3] Comprised of Aldoga Solar Farm, Punchs Creek Solar Farm and Wandoan Solar Farm Stage 2 (Powerlink).

[4] Refer to Table 6.1 for the available generation capacity of power stations connected or committed to be connected to Powerlink's transmission network.

Figure 1.3 Existing and committed connection projects since 2017



1.6 Connecting to our network

1.6.1 The connections process

Participants wishing to connect to the Queensland transmission network include new and existing generators, storage, major loads and other Network Service Providers (NSPs). New connections or alterations to existing connections requires Powerlink and the connecting party to negotiate an Offer to Connect and Connection and Access Agreement (CAA), and the specification and compliance of the generator or load to the required technical standards. The process of agreeing to technical standards also involves AEMO. The services provided can be prescribed for Distribution NSPs (regulated), negotiated or non-regulated services in accordance with the definitions in the NER or the framework for provision of such services.

While the pipeline of connection projects far exceeds the expected requirements for the next 10 years, not all projects will meet their financial investment decision timeframes. For example, there are 12 projects for which Powerlink has completed Generator Performance Standards assessments since December 2023 that are yet to reach committed status. For the significant majority of these projects, the delays are due to factors outside Powerlink's control.

1.6.2 Categories of connection assets

Dedicated Connection Assets

All new Dedicated Connection Asset (DCA) services, including design, construction, ownership, and operation and maintenance are non-regulated services.

Identified User Shared Assets

Identified User Shared Asset (IUSA) services are either negotiated or non-regulated services, depending on specific requirements set out in Chapter 5 of the NER. Powerlink remains accountable for operation and maintenance of all IUSAs as part of the transmission network.

Designated Network Assets

Designated Network Assets (DNA) include radial transmission extensions greater than 30km in length. Unlike DCAs, DNAs are part of the transmission network, with design, construction, and ownership as non-regulated services. Powerlink remains accountable for the operation and maintenance of all DNAs[5].

Powerlink remains committed to transparent and efficient connection services and will continue to work collaboratively with market participants and interested parties to better understand the potential for new generation and load connections, and to identify opportunities and emerging limitations as they occur. The NER (rule 5.3) prescribes procedures and processes that NSPs must apply when dealing with connection enquiries.

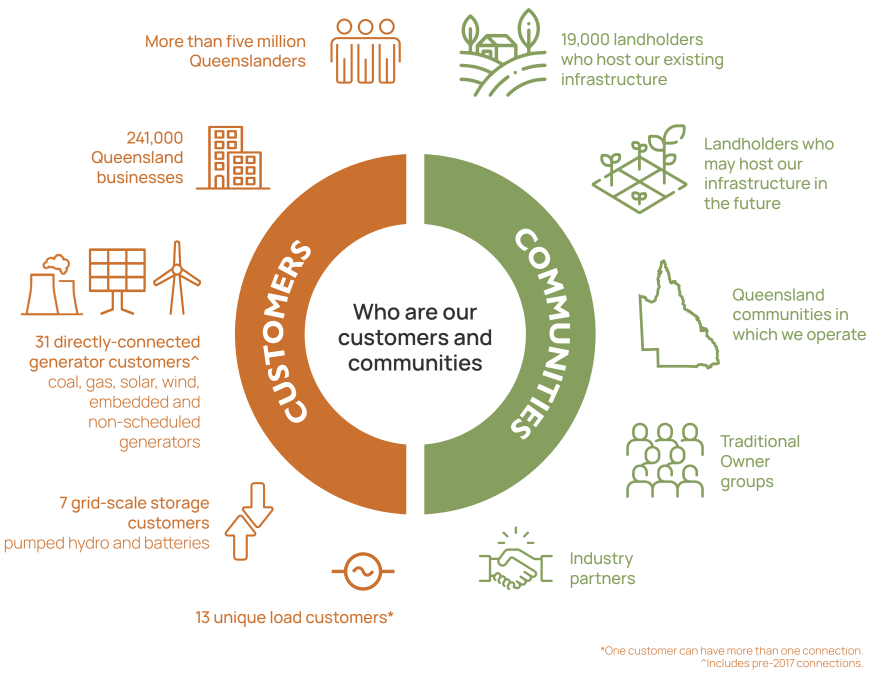
Figure 1.4: Overview of Powerlink's existing network connection process

Proponents who wish to connect to Powerlink's transmission network are encouraged to contact connections@powerlink.com.au. For further information on Powerlink's network connection process refer to Powerlink's website.

1.7 Customer, stakeholder and community engagement

Powerlink is committed to effective, targeted engagement with customers, communities, First Nations Peoples and other stakeholders to share information on activities and use feedback received to improve decision making.

Figure 1.5 Powerlink's customers and communities



There are also stakeholders who provide Powerlink with non-network solutions that can either connect directly to Powerlink's transmission network, or to the distribution network.

[5] Refer to Appendix J for information about which parts of Powerlink's transmission network are DNAs.

Engagement activities

Powerlink's engagement activities are undertaken in accordance with our Stakeholder Engagement Framework and Community Engagement Approach, which set out the principles, objectives and outcomes Powerlink seeks to achieve in our interactions with stakeholders and the broader communities in which we operate. A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement goals. In particular, Powerlink undertakes a comprehensive stakeholder survey to gain insights about stakeholder perceptions of Powerlink, including key factors driving trust and reputation. Most recently completed in August 2025, the survey provides comparisons and year on year trends to inform engagement strategies with stakeholders. More detailed information on Powerlink's engagement activities is available on the Powerlink website.

Community engagement

Engaging with communities is essential to providing transmission services that are safe, reliable and cost-effective. Transmission infrastructure typically stays in service for over 50 years and Powerlink is focused on building positive relationships and partnering with local communities to deliver benefits for the longer term. First developed in 2021, the Community Engagement Approach was refreshed in 2025 to continue driving best-practice engagement and generating lasting benefits for communities. The focus of Powerlink's engagement has not changed – engaging early and often, particularly with communities where Powerlink is building new infrastructure and connecting renewable development projects.

Powerlink also undertook targeted community sentiment research in key areas of the state to gauge community acceptability of renewable development and related transmission infrastructure. The research showed that trust and acceptance had declined modestly on the previous year, and that declining trust reflected challenges in the local value proposition of renewable development for communities[6]. The research findings support Powerlink's future engagement and ensure an ongoing focus on what is important to communities, who remain front and centre in our planning and decision making.

Targeted external engagement

In November 2024, more than 600 customers attended (in person and virtually) Powerlink's annual Transmission Network Forum. The forum provided updates on the state of the network, discussion on project work in Central Queensland and a technical session on the 2024 TAPR. The live stream recordings, presentations, questions and answers are available on Powerlink's website.

In August 2025, more than 100 people attended Powerlink's first regional Transmission Network Forum, held in Gladstone. The forum brought together government, industry and community representatives to discuss the important role that Central Queensland will play in the state's future power system.

Customer Panel

Powerlink hosts a Customer Panel that provides an interactive forum for its stakeholders and customers to give input and feedback to Powerlink regarding decision making, processes and methodologies. The panel comprises members from a range of sectors including industry associations, community advocacy groups, directly connected customers and distribution representatives. It also provides an important channel for Powerlink to keep stakeholders informed about operational and strategic topics of relevance and, most importantly, provides an avenue for their insights on particular activities. The panel met in September 2024, and in April and July 2025, to consider key topics of interest. Members of the Customer Panel also offered their time to be part of Powerlink's new Revenue Proposal Reference Group, as well as an expert panel on the Gladstone Project Priority Transmission Investment (PTI).

Stakeholder engagement for public consultation processes

Powerlink recognises the importance of transparency for stakeholders and customers, particularly when undertaking transmission network planning and engaging in public consultation processes, such as the Regulatory Investment Test for Transmission (RIT-T) or a PTI.

Powerlink is guided by the Australian Energy Regulator (AER) Stakeholder Engagement Framework and Consumer Engagement Guideline for Network Service Providers as the benchmarks when undertaking public consultations.

Since publication of the 2024 TAPR, to ensure transparency and that customers remain up to date with the most recent developments, Powerlink has also held webinars on topics such as transmission network planning and addressing system strength requirements. Webinar recordings and presentations are available on Powerlink's website.

6 Trust dropped from 3.1 (in a 1-5 range) two years ago to 2.9 in 2024. Similarly, acceptance slipped from 3.2 down to 2.9. These shifts are considered statistically important in terms of sentiment towards Powerlink.

Energy and demand projections

02

02. Energy and demand projections

This chapter describes Queensland's historical energy and demand, provides forecast regional data disaggregated by zone, and explains the key drivers of demand and energy forecasts.

Key highlights

- Queensland's maximum transmission delivered demand for 2024/25 was 9,974 megawatts (MW) on Wednesday, 22 January 2025. This maximum demand occurred at 6.00pm and was 545MW higher than the previous record maximum delivered demand set in January 2024.
- Queensland set a new record minimum transmission delivered demand of 2,240MW on Sunday, 31 August 2025. This minimum demand occurred at 11.30am and was 298MW lower than the previous record minimum demand set in October 2024.
- The increasing adoption of rooftop solar photovoltaic (PV) and distribution-connected solar systems continues to reduce daytime electricity demand. However, the 2025 residential and commercial solar PV forecasts have been revised downward due to the inclusion of decommissioned rooftop solar systems in the forecast.
- The rising adoption of residential batteries has introduced new charging loads during traditionally low-demand periods. This change, coupled with a more moderate projection of solar PV uptake, has led Powerlink to forecast a slower decline in minimum demand compared to the previous year's forecast.
- The residential battery adoption rate is projected to nearly double compared to 2024 predictions, driven mainly by rapidly declining equipment costs and new government rebates. This increased uptake rate has boosted midday charging loads, helping to further stabilise declining minimum demand forecasts.
- While Powerlink's forecast for electric vehicle uptake remains largely consistent with the 2024 Transmission Annual Planning Report (TAPR), the future charging behaviour of electric vehicle owners is a key source of forecasting uncertainty. If charging is unmanaged, owners might charge during peak evening hours and add strain to the grid, whereas smart charging via time-of-use tariffs will move charging away from evening peaks.
- Powerlink has not included specific data centre projects into the demand forecast for Queensland at this time. Powerlink will continue to monitor developments and adjust future forecasts accordingly if significant interest for data centres in Queensland materialises.
- Based on Powerlink's Central scenario forecast, Queensland's:
  - transmission delivered maximum demand is expected to have steady growth with an average annual increase of 2.2% per annum over the next 10 years. This increase is mainly due to industries beginning to electrify and new anticipated loads.
  - transmission delivered minimum demand is expected to steadily decrease with an average annual decrease of 6.3% per annum over the next 10 years. This decrease is mainly due to the continued installation of residential rooftop solar PV systems.

2.1 Introduction

This chapter:

- explains key demand and energy terminology
- details Powerlink's forecast of energy and demand over the 10-year period
- includes historical energy and demand
- highlights some of the key drivers of forecasting demand
- provides seasonal demand forecasts and forecasts by zone[1].

Demand and energy forecast information is also available in the TAPR Portal.

1 As required by National Electricity Rules (NER), clauses 5.12.1(a) and (b)(1).

2.1.1 Forecasting demand and energy

Accurate demand and energy forecasting is a critical input for Powerlink to deliver safe, reliable and cost-effective transmission services. These forecasts underpin critical decisions on infrastructure investments and grid stability.

However, the rapidly evolving energy landscape introduces significant uncertainties that challenge the accuracy of the forecast. Uncertainties are driven by:

- variable load growth due to dynamic economic factors impacting industrial expansions in mining and manufacturing
- the pace of electrification, particularly in transport and industrial processes
- adoption of electric vehicles and uncertainties around charging behaviours
- uptake of behind the meter energy storage
- global commodity prices and policy shifts.

Adding to these challenges is the impact of Queensland's variable weather, which significantly influences electricity demand, particularly through air conditioning loads during extreme heatwaves or prolonged wet seasons. Climate projections also suggest increasing frequency and intensity of such events, disrupting historical weather-normalisation models and amplifying demand fluctuations.

These factors, combined with the intermittency of renewable generation, underscore the critical need for scenario-based and probabilistic forecasting methods that Powerlink has incorporated into the forecasting process.

2.2 Powerlink forecast tool

Powerlink has developed a transmission delivered demand and energy forecast tool. The tool enables Powerlink to produce sub-regional forecasts, and to forecast future load (new and/or as a result of electrification), in High, Central and Low scenario forecasts. Powerlink's forecast also includes sub-regional areas, otherwise known as TAPR zones, and provides greater granularity across the transmission network. The Powerlink forecast tool uses inputs from a variety of sources[2].

The Powerlink forecast process individually models a range of building blocks that impact electricity demand:

- native demand
- solar PV
- electric vehicles
- residential batteries
- block loads
- embedded generation.

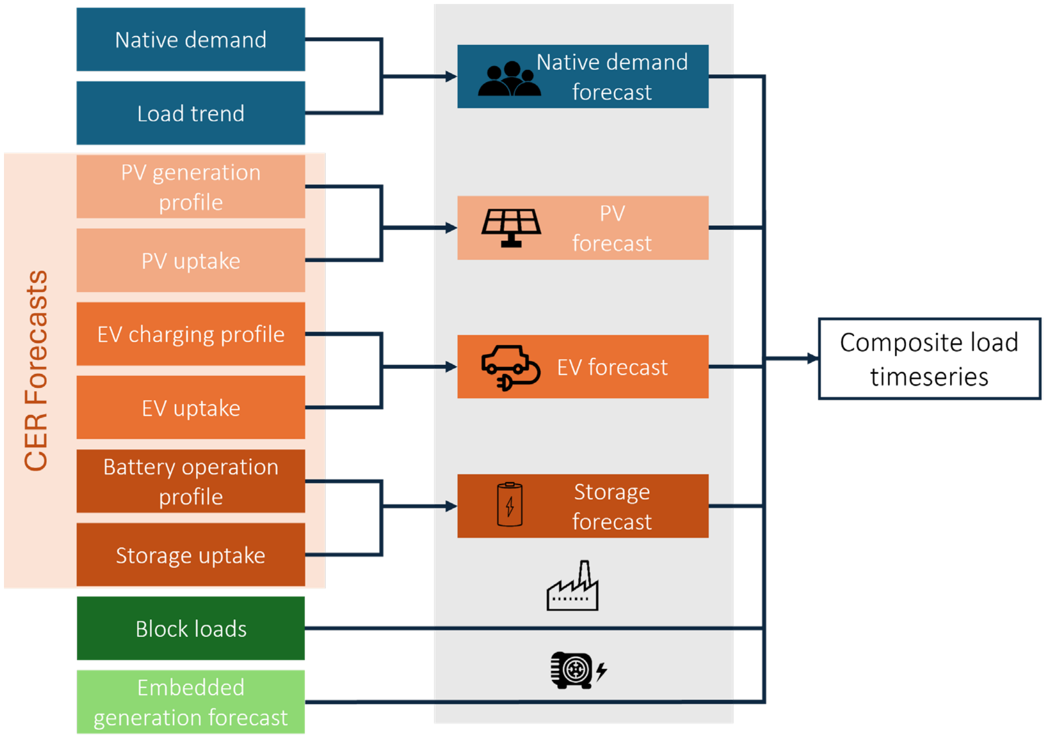
Powerlink endeavours to use the best available data sources. The forecast tool incorporates latest assumptions for macroeconomic factors and evolving trends in energy consumption and technology adoption, with sources including:

- Australian Bureau of Statistics (ABS)
- Queensland Government
- Australian Energy Market Operator (AEMO)
- Deloitte Access Economics economic forecasts
- CSIRO GenCost reports[3]
- data from Energy Queensland and Powerlink customers.

Figure 2.1 presents a schematic of the individual building blocks that make up the aggregate demand forecast. Independent sub-models are derived for the different consumer energy resource (CER) technologies, native demand trends, block loads and embedded generation. Composite load traces are constructed from the output of each sub-model.

[2] Detail on the High, Central and Low scenarios, and the sources used for the forecasting tool, located in Appendix D.
[3] CSIRO, GenCost 2024-25, final report, July 2025.

Figure 2.1 Powerlink's forecasting components



2.3 Forecasting assumptions and key drivers

2.3.1 Energy Queensland consultation

Energy Queensland provided summer and winter maximum demand forecasts for both the Energex and Ergon Energy distribution networks, over a 10-year outlook period. Powerlink produced transmission connection supply point forecasts that incorporate Energy Queensland's inputs. These connection supply point forecasts are presented in Appendix D.

Powerlink is proactively engaging with customers to understand their future load requirements. To enable efficient planning of the network, early customer engagement is required to allow transmission network services to be developed in ways that are valued by customers.

Powerlink and Energy Queensland jointly conduct the Queensland Household Energy Survey (QHES) to improve understanding of customer behaviours and intentions. More than 4,000 participants completed the survey in 2025[4].

2.3.2 Consumer Energy Resources

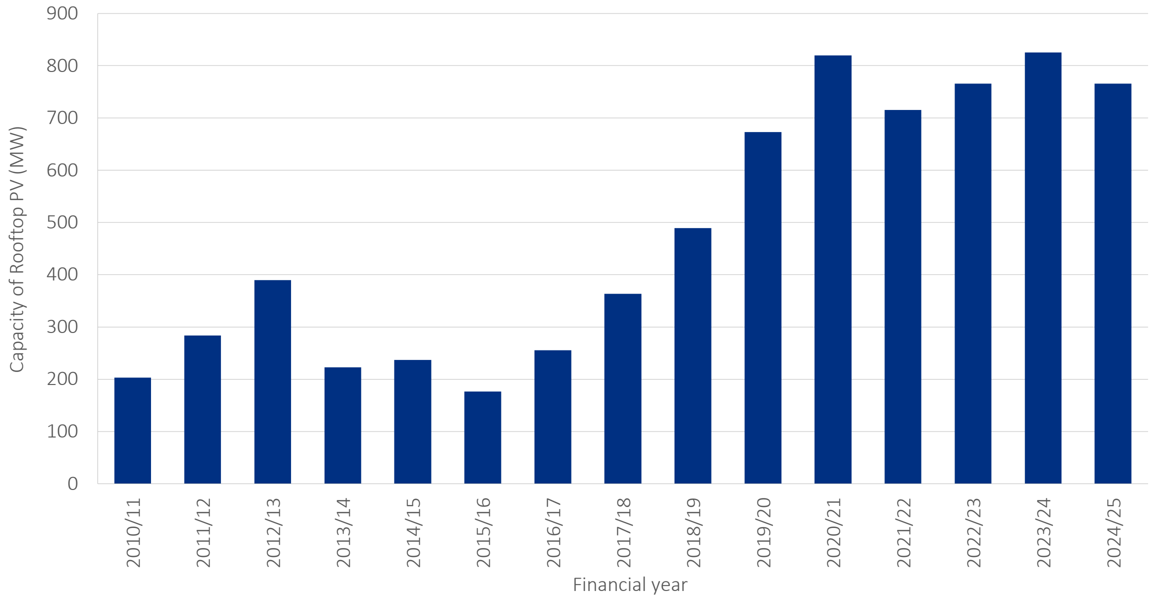
Powerlink works with Energy Queensland to derive forecasts for CER. Energy Queensland maintains a register of numbers, capacity and location of solar PV, electric vehicle and residential battery installations. This data provides insight into trends that can be projected forward. The uptake of rooftop solar PV systems is expected to continue with the 2025 QHES indicating that 24% of respondents intend to purchase new or upgrade existing rooftop solar PV systems in the next three years.

2.3.3 Rooftop solar PV

Rooftop solar PV installations continue to grow at a steady rate with a further 765MW being installed over the last 12 months. Expiry of the 44 cent per kilowatt hour feed-in-tariff on 1 July 2028 could see a spike in new installations as customers upgrade their solar PV systems.

4 Powerlink and Energy Queensland, Queensland Household Energy Survey 2025.

Figure 2.2 Net increase in capacity of Queensland rooftop solar PV (1) (2) (3)



Notes:

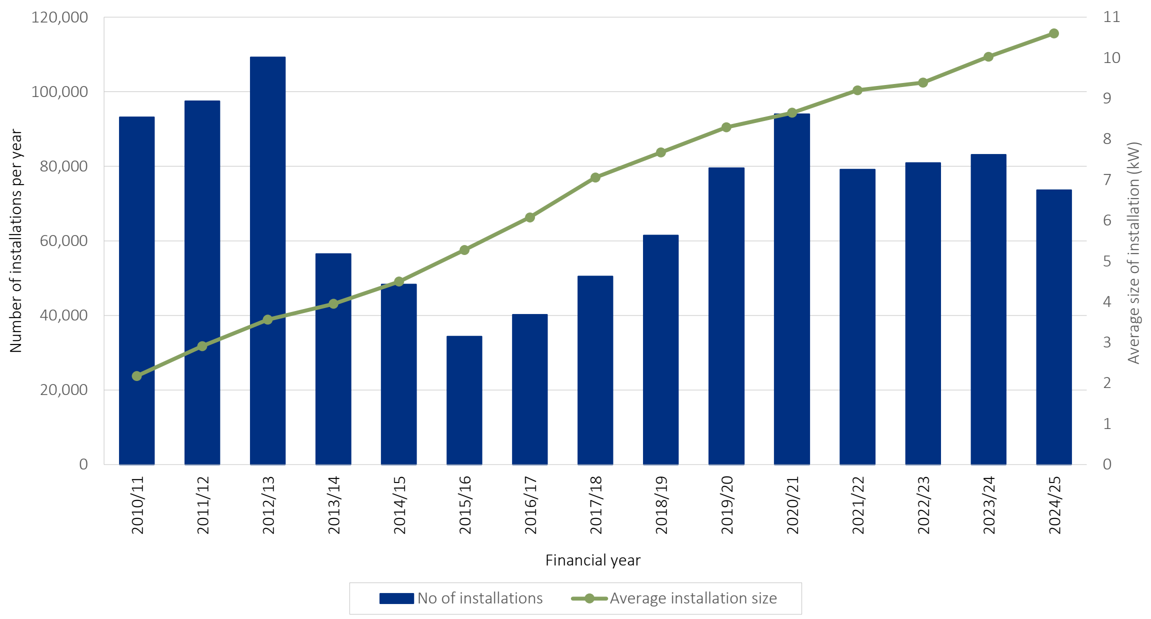
(1) Source: Clean Energy Regulator, Small-scale Installation Postcode Data.

(2) Registrations generally lag installations and hence data for FY2025 may be slightly understated.

(3) Installed panel capacity.

The historical solar PV register now includes the decommissioning of old rooftop solar PV systems, resulting in a revised solar PV forecast that has decreased compared to the 2024 forecast[5].

Figure 2.3 Annual installation rates and average sizes for Queensland rooftop solar PV (1) (2)



Notes:

(1) Source: Clean Energy Regulator, Small-scale Installation Postcode Data.

(2) Registrations generally lag installations and hence data for FY2025 may be slightly understated.

5 For example, if a customer installed a 5kW system in 2012 and added another 10kW to the system in 2020, previously the historical solar PV register recorded this as a single entry of 15kW installed in 2020. This had the effect of showing faster growth in solar PV than was actually the case. Correcting this error has led to the solar PV forecast being revised down.

2.3.4 Residential batteries

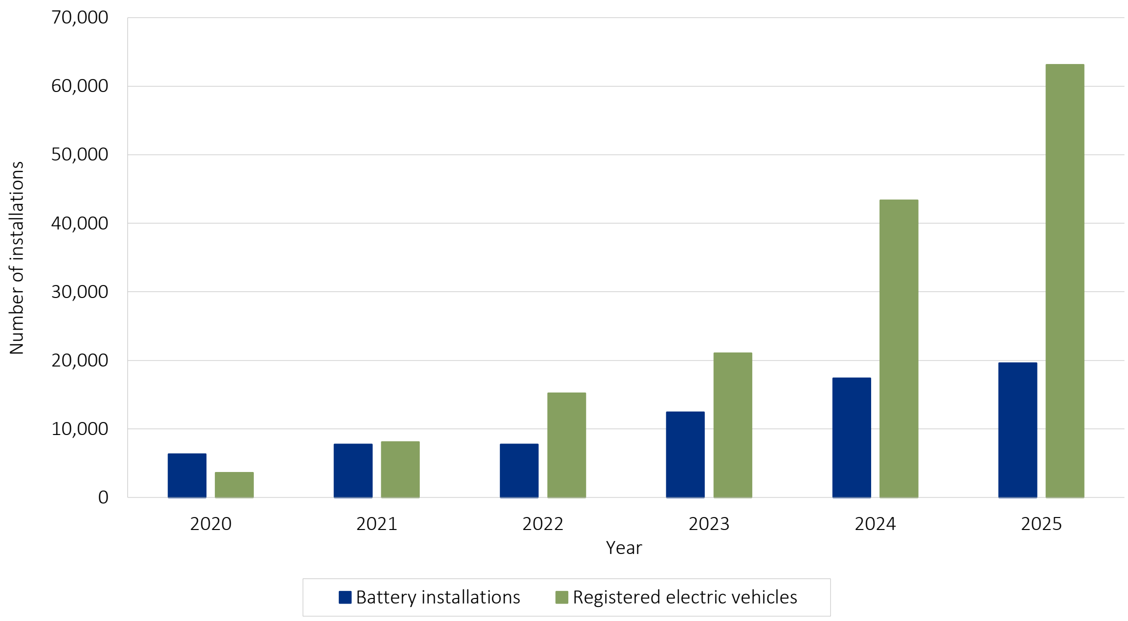
Residential batteries have seen steady growth over the last 12 months. As a result, faster uptake rates have been incorporated into the battery forecasts. Government subsidies are expected to increase the battery uptake across all scenarios. According to the recent QHES, 62% of households have either already installed batteries (21%), intend to purchase battery storage in the next 3 years (18%) or in the next 3-10 years (23%). The majority (52%) of households that have or intend to purchase a battery in the next three years indicated it is to store excess solar energy and use it later during peak times to reduce electricity use from the grid. Further, 37% of respondents have high interest in community batteries.

2.3.5 Electric vehicles

The forecast for electric vehicle uptake in 2025 remains largely consistent with the 2024 TAPR values. The 2024 TAPR estimated that 59,000 electric vehicles would be registered by 2025. Actual registrations as of January 2025 reached approximately 63,000, indicating a slightly higher adoption than expected, resulting in a slight uplift in the electric vehicle forecast for 2025.

The future charging behaviour of electric vehicle owners is a key source of uncertainty in forecasting assumptions. If charging is unmanaged, owners might charge during peak evening hours and add strain to the grid. Energy retailers' smart charging via time-of-use tariffs is already moving charging away from evening peaks. According to the recent QHES, of the households with electric vehicle ownership, 66% are open to the concept of their vehicle charging being managed by a third party.

Figure 2.4 Queensland residential battery uptake (1) and number of registered electric vehicles (2)



Notes:

(1) Source: Clean Energy Regulator, Small-scale Installation Postcode Data.

(2) Source: Queensland Government, Electric Vehicle Snapshot.

2.3.6 Hydrogen

Hydrogen load forecasts have undergone a notable reduction since 2024 TAPR, due to several hydrogen projects being withdrawn.

Powerlink's 2024 TAPR Central scenario included substantial hydrogen-related block loads, particularly in Gladstone and South Queensland. However, recent developments, such as the cancellation of large hydrogen projects and an electrolyser initiative in Gladstone, have led to the removal of these loads from the forecast.

This revised outlook is also captured in Table 2.1 compared to its counterpart in the 2024 TAPR.

While some upside risk remains, the current trajectory suggests a more cautious and measured integration of hydrogen into Queensland's energy landscape. This recalibration aligns with global trends, as highlighted in the International Energy Agency's Global Hydrogen Review 2024, which notes slower than anticipated progress in project implementation and demand creation worldwide.

2.3.7 Data centres

Powerlink acknowledges the substantial data centre expansions occurring in New South Wales and Victoria, driven by factors such as proximity to major population centres and established digital infrastructure. These trends have not translated to date in Queensland, as evidenced by the limited interest from data centre proponents in Queensland, with minimal enquiries or developments progressing beyond preliminary stages.

Further, AEMO has projected only a modest 90 gigawatt hours (GWh) of annual consumption for data centres in Queensland (from 2025/26 to 2054/55) in its 2025 Inputs, Assumptions and Scenarios forecast[6]. This reflects a conservative outlook, which is aligned with current market signals.

As a result, Powerlink has not included specific data centre projects into the current load forecast. Powerlink will continue to monitor emerging developments in this area and adjust future forecasts accordingly if significant interest materialises.

2.3.8 Electrification of load and decarbonisation

In 2023/24, approximately 21% of final energy consumption in Queensland was from electricity and this electrical energy was predominantly supplied from the interconnected power system[7]. The majority (79%) of energy consumption in Queensland has historically been supplied by the combustion of fossil fuels used in various sectors of the economy such as transport, agriculture, mining and manufacturing. The drivers for electrification of these sectors largely relate to the need to reduce carbon emissions for a variety of reasons including environmental, community and corporate expectations or the international treatment of exports with implicit emissions. Electrification of this load is likely to require a significant investment in the transmission and distribution networks and in new generation.

The growth in grid-supplied electricity resulting from electrification will, to some extent, be offset by efficiencies. For example:

- electric vehicles are more efficient than petrol cars, and
- behind the meter generation at both the commercial and domestic levels is a more efficient way to supply a load as losses are reduced.

However, the geospatial distribution of these two effects is not expected to be uniform. There may be areas where net demand for grid-supplied electricity significantly increases, and other areas where it decreases.

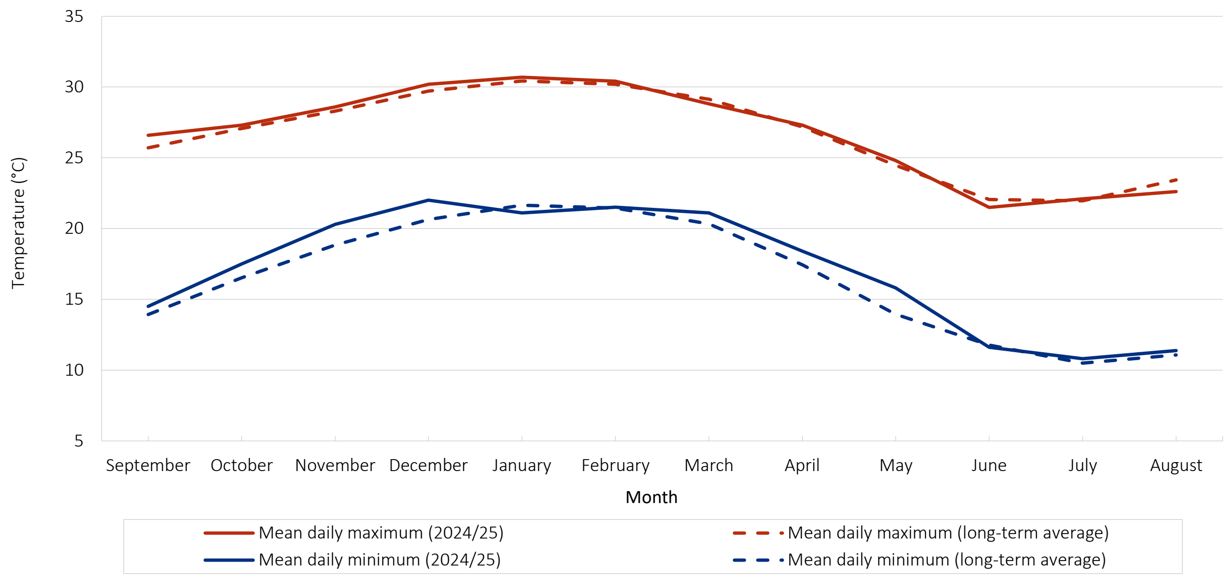
Powerlink is committed to developing an understanding of the future impacts of emerging technologies and electrification, and to working with our customers and AEMO so that these are accounted for geospatially within future forecasts. This will allow transmission network services to be developed in ways that are valued by customers.

2.3.9 Weather

Queensland's demand is highly sensitive to the sub-tropical climate and temperature variations, with heatwaves amplifying peak loads. Figure 2.5 shows observed mean temperatures for Brisbane during September 2024 to August 2025 compared with long-term averages. The comparison reveals a slightly hotter summer than average in south-east Queensland and the winter minimum temperatures in July and August were also warmer than the long-term average. The high summer temperatures were accompanied by extreme relative humidity, especially in January, which was the primary contributor to the record maximum demand that month.

6 AEMO, 2025 Inputs, Assumptions and Scenarios Workbook (Data Centre Forecasts), August 2025.
7 Department of Climate Change, Energy, the Environment and Water, Australian Energy Statistics, Table D, August 2025.

Figure 2.5 Brisbane temperature ranges over September 2024 to August 2025 (1)



Note:

(1) Long-term average based on years 2000 to 2024/25[8].

2.3.10 Transmission connected customers

Powerlink obtained summer and winter maximum demand forecasts from customers that connect directly to the Powerlink transmission network[9].

2.3.11 New large loads

No new large loads have connected in the past 12 months.

2.3.12 Possible new large loads

There are several proposals under development for new large mining, metal processing, other industrial loads and for the electrification of existing loads. These proposed large loads total approximately 2,982MW. The likely distribution of these loads is shown in Table 2.1.

The majority of proposed loads have been included in Powerlink's High scenario forecast only. Powerlink's Central scenario forecast allows for approximately 600MW of anticipated electrification load. This anticipated load ramps up over the forecast period beginning from 2027/28. The loads in Table 2.1 are not included in the Low and Central scenario forecasts.

Table 2.1 Possible large loads excluded from the Low and Central scenario forecasts

Zone	Description	Possible load
North Queensland	Electrification Manufacturing	1,500MW
Central Queensland	Hydrogen production Electrification	1,372MW
Southern Queensland	Technology Transport infrastructure	110MW

8 Bureau of Metereology, Monthly Mean Maximum Temperature (Brisbane).
9 NER, clause 5.11.1.

2.4 Forecast highlights

Powerlink's energy forecasts for 2025 show steady growth in transmission delivered summer maximum demand at an average rate of 2.2% per annum over the 10-year period. The increase is mainly due to industries beginning to electrify their operations in the Gladstone zone.

Powerlink also forecast a decline in annual transmission delivered minimum demand over the 10-year period. Minimum demand, or minimum system load, is the lowest amount of energy flowing across the network at a given time, and has continually decreased over the past seven years, largely driven by uptake of rooftop solar PV and distribution-connected solar systems.

Queensland set new records for both minimum and maximum transmission delivered demand in 2024/25:

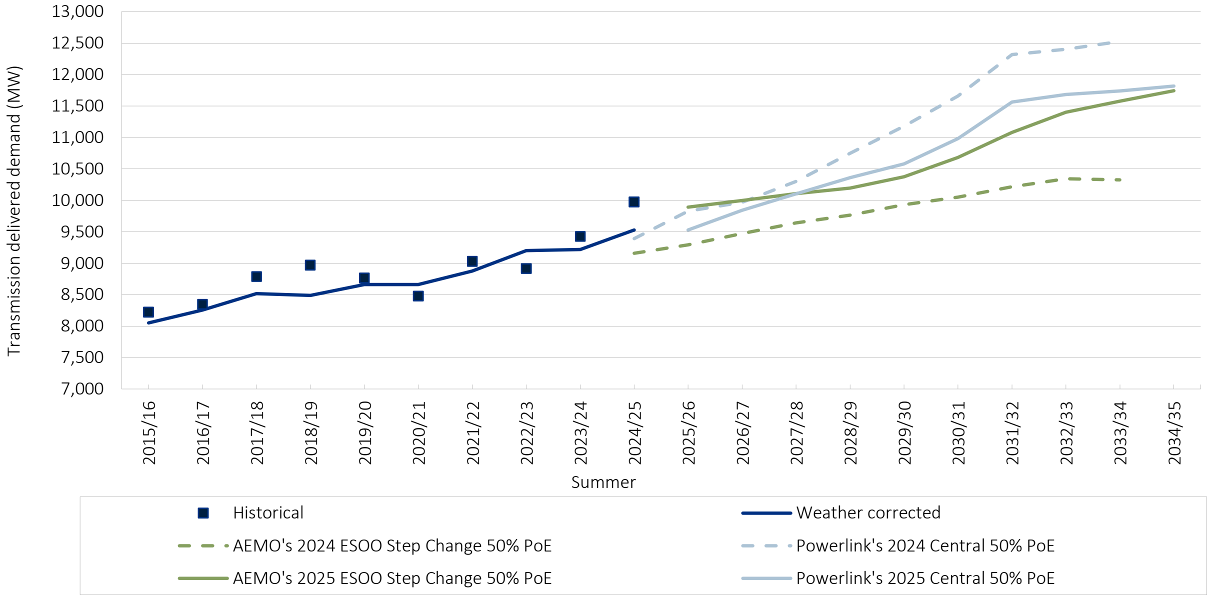
- On Sunday 31 August 2025, minimum transmission delivered demand reached 2,240MW, which was 298MW lower than the previous record set in October 2024.
- On Wednesday 22 January 2025, maximum transmission delivered demand reached 9,974MW, which was 545MW higher than the previous record set in January 2024.

2.5 Maximum delivered demand

The 2024/25 maximum transmission delivered demand in Queensland occurred at 6.00pm on 22 January 2025, when 9,974MW was delivered from the transmission grid (refer to Figure 2.10 for load measurement definitions). Operational as-generated peak demand was recorded at the same time, reaching 11,144MW. After weather correction, the 2024/25 summer maximum transmission delivered demand was 9,529MW, 0.6% higher than Powerlink's 2024 forecast for 2024/25.

Figure 2.6 shows a comparison of AEMO's 2024 and 2025 Electricity Statement of Opportunities (ESOO) delivered summer maximum demand forecasts based on the Step Change scenario with Powerlink's 2024 and 2025 Central scenario, all with 50% Probability of Exceedance (PoE). The reduction in Powerlink's forecast maximum demand primarily results from removing an anticipated hydrogen project, included in the 2024 TAPR Central scenario forecast.

Figure 2.6 Comparison of AEMO's 2024 and 2025 ESOO Step Change scenario forecast with Powerlink's 2024 and 2025 Central scenario 50% PoE delivered demand forecast (1)



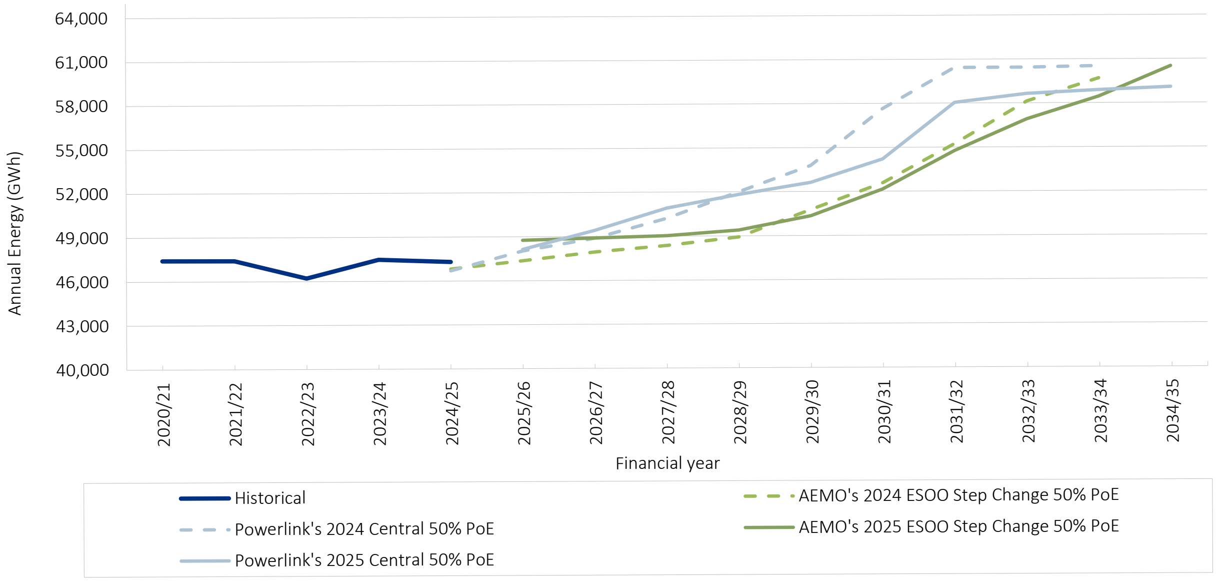
Note:

(1) AEMO's 2024 and 2025 ESOO forecast has been converted from operational sent out to transmission delivered for the purposes of comparison. Refer to Figure 2.10 for further details.

2.6 Annual delivered energy

Powerlink's energy forecast has been adjusted downward following the removal of the anticipated hydrogen project. This reduction is partially offset by an updated solar PV forecast, which reflects the anticipated decommissioning of rooftop solar PV, thereby increasing demand on the transmission network. Figure 2.7 compares AEMO's 2024 and 2025 ESOO energy forecasts under the Step Change scenario with Powerlink's 2024 and 2025 Central scenario forecasts. The growth observed in the forecast can be attributed to electrification of existing load and the reduced solar PV output assumed in the forecast this year.

Figure 2.7 Comparison of AEMO's 2024 and 2025 ESOO Step Change scenario energy forecast with Powerlink's 2024 and 2025 Central scenario delivered energy forecast (1)



Note:

(1) AEMO's 2024 and 2025 ESOO[10] forecast has been converted from operational sent out to transmission delivered for the purposes of comparison. Refer to Figure 2.10 for further details.

2.7 Minimum delivered demand

The 2025 Queensland minimum transmission delivered demand occurred at 11:30am on Sunday, 31 August 2025, when only 2,240MW was delivered from the transmission grid (refer to Figure 2.10 for load measurement definitions). Operational as-generated minimum demand was recorded at the same time at 2,790MW and was 301MW lower than the 2024 record minimum set in October 2024.

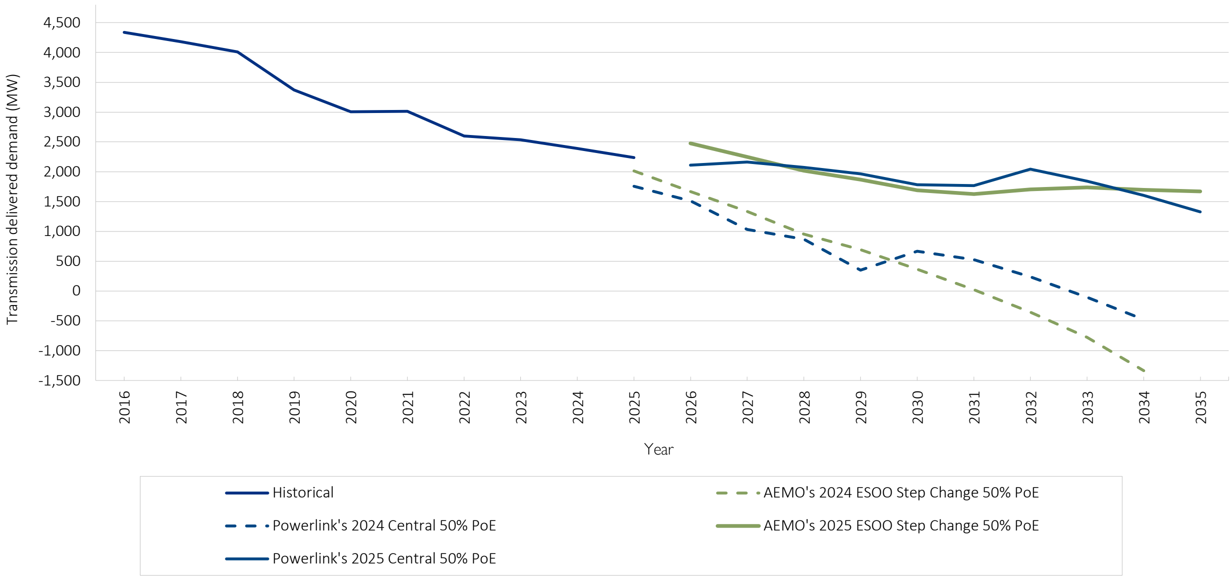
At the time of minimum transmission delivered demand, directly connected loads made up about 77.5% of the transmission delivered demand with Distribution Network Service Provider (DNSP) customers making up the remainder. Mild weather conditions, during a weekend in combination with strong contribution from rooftop solar PV were contributors to this minimum demand.

Figure 2.8 shows a comparison of AEMO's 2024 and 2025 ESOO annual delivered minimum demand forecast based on AEMO's Step Change scenario with Powerlink's 2024 and 2025 Central scenario. Both minimum demand forecasts indicate a slower decline in minimum demand compared to the previous year. A key driver of this trend is the inclusion of anticipated decommissioned rooftop solar PV into the forecast.

This adjustment results in a more moderate projection of rooftop solar PV uptake, reducing its impact on minimum demand periods. Additionally, the rising adoption of residential batteries, driven by falling equipment costs and government incentives, has introduced new charging loads during traditionally low-demand periods.

10 AEMO, Electricity Forecasting Data Portal.

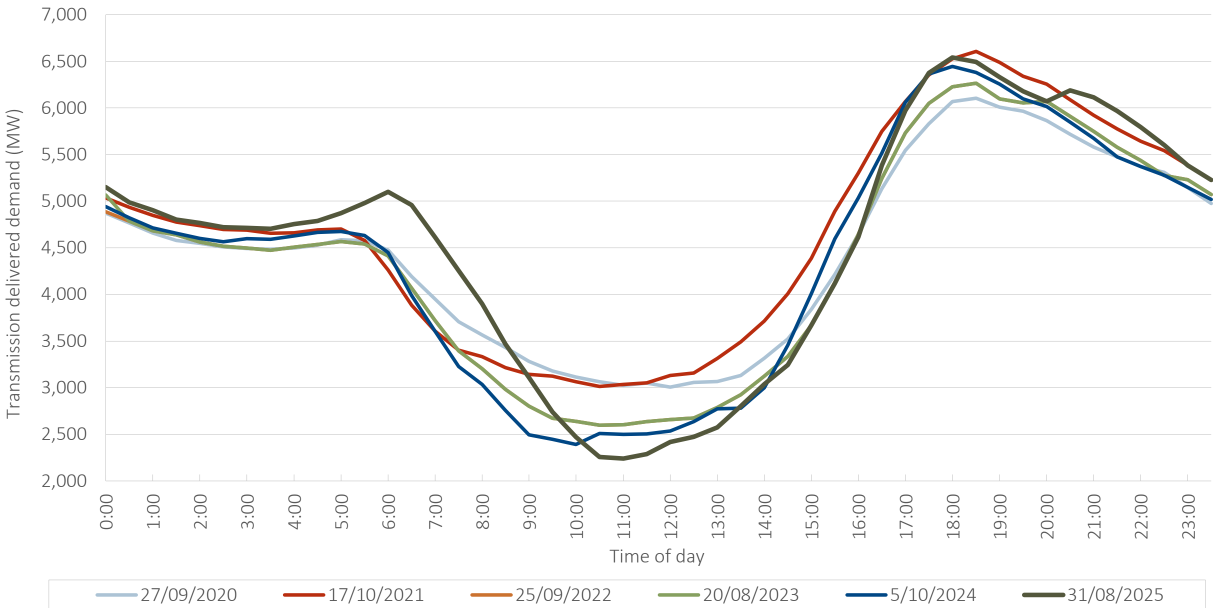
Figure 2.8 Comparison of AEMO's 2024 and 2025 ESOO[11] Step Change scenario minimum delivered demand forecast with Powerlink's 2024 and 2025 Central scenario (1)



Note:

(1) AEMO's 2024 and 2025 ESOO forecast has been converted from operational sent out to transmission delivered for the purposes of comparison. Refer to Figure 2.10 for further details.

Figure 2.9 Transmission delivered minimum demand for the Queensland region (1)



Note:

(1) 2025 trace based on preliminary metering data up to 18 September 2025.

Minimum demand during the day has continued to decrease since 2016 due to the progressive installation of rooftop solar PV and distribution network solar system connections. However, maximum daily demand has continued to increase in line with underlying load growth since the contribution of rooftop solar PV tapers off towards the evening, resulting in an increasing divergence between minimum and maximum demand. The increased maximum demand needs to be met and managed by large-scale generation and the transmission network as it occurs at a time when solar PV is not generating. With the expected continued uptake of residential and commercial rooftop solar PV installations, and in the absence of significant levels of demand shifting or distributed energy storage, minimum demand levels are expected to further decrease with a continued widening between maximum and minimum demand.

[11] AEMO, Electricity Forecasting Data Portal.

2.8 Demand forecast

The following sections outline the Queensland forecasts for energy, summer maximum demand, winter maximum demand and minimum demand. Maximum demands continue to be expected in the summer period, whereas minimum demands previously occurred in winter and have now shifted to the shoulder seasons.

The 2025 TAPR reports on the High, Central and Low scenario forecasts produced by Powerlink. Demand forecasts are also prepared to account for yearly weather variations. These weather variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent load conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

The forecast average annual growth rates for the Queensland region over the next 10 years under High, Central and Low scenarios are shown in Table 2.2. These growth rates refer to transmission delivered quantities as described in Section 2.8.1. The summer and winter maximum demand growth rates are based on 50% PoE corrected values for 2024/25 and 2024 respectively.

Table 2.2 Average annual growth rate over next 10 years

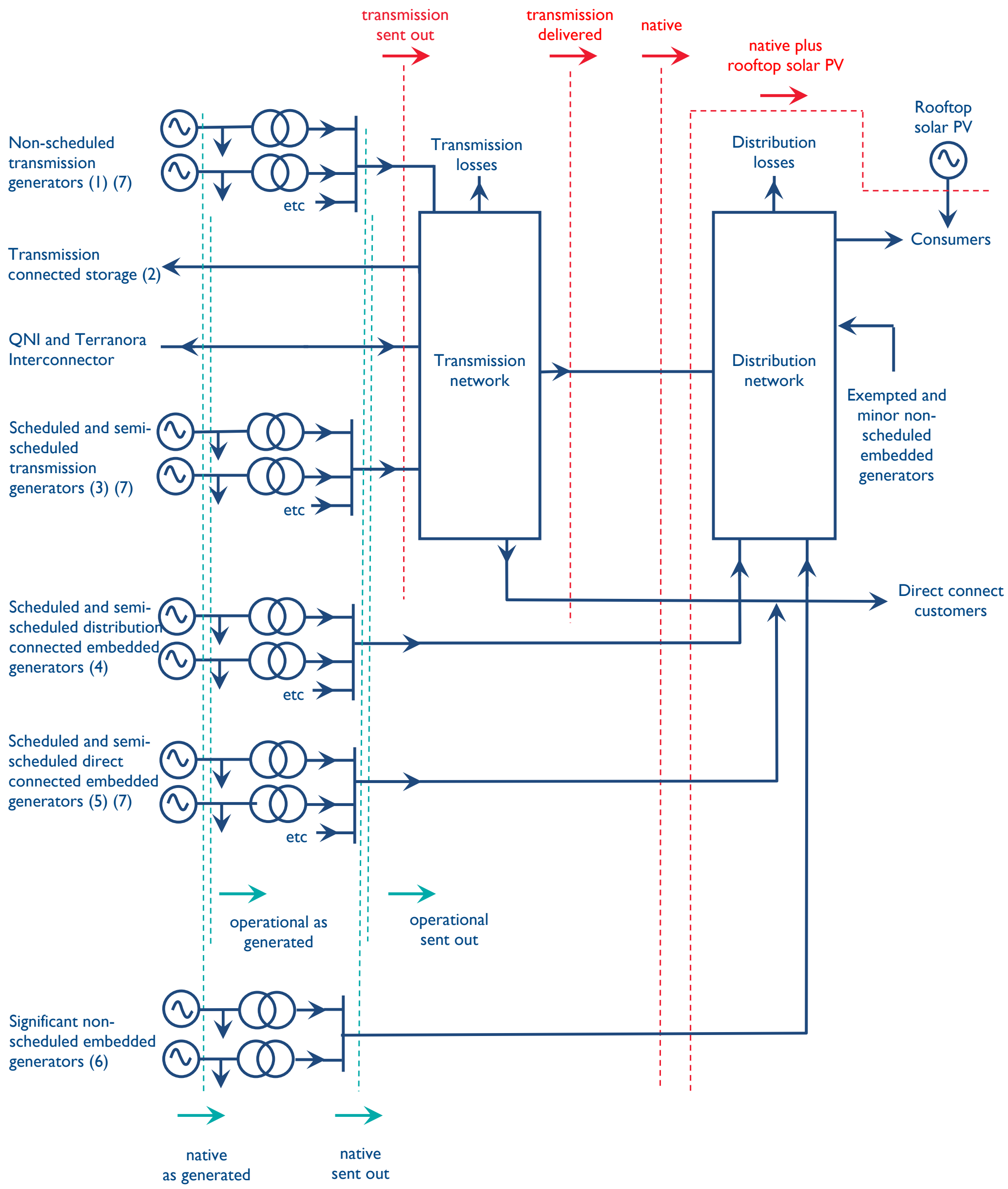
	Powerlink future scenario outlooks		
	High	Central	Low
Delivered energy	6.1%	2.2%	-1.9%
Delivered summer maximum demand (50% PoE)	5.0%	2.2%	-1.2%
Delivered winter maximum demand (50% PoE)	4.7%	2.0%	-1.1%

The forecast for minimum delivered demand is closely correlated to forecast rooftop solar PV installations and embedded variable renewable energy (VRE) generators. Forecasts in this chapter are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but impact on the output of these embedded VRE generators.

2.8.1 Demand and energy terminology

The reported demand and energy on the network depend on where it is being measured. Individual stakeholders have reasons to measure demand and energy at different points. Figure 2.10 shows the common ways demand and energy measurements are defined, with this terminology used consistently throughout the TAPR.

Figure 2.10 Load measurement definitions



Notes:

(1) Includes Invicta and Koombooloomba.

(2) Including pump and battery loads.

(3) Includes Yarwun which is non-scheduled.

(4) For a full list of scheduled and semi-scheduled distribution connected generators refer to Table 6.2.

(5) Sun Metals Solar Farm and Condamine.

(6) Lakeland Solar and Storage, Hughenden Solar Farm, Pioneer Mill, Moranbah North, Racecourse Mill, Barcaldine Solar Farm, Longreach Solar Farm, German Creek, Oaky Creek, Baking Board Solar Farm, Sunshine Coast Solar Farm and Rocky Point.

(7) For a full list of transmission network connected generators, Battery Energy Storage Systems (BESS) and scheduled and semi-scheduled direct connected embedded generators and BESS, refer to Table 6.1.

2.8.2 Energy forecast

Historical Queensland energy measurements are presented in Table 2.3. They are recorded at various levels in the network as defined in Figure 2.10.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled power station auxiliaries are the difference between operational as generated and operational sent out energy.

Table 2.3 Historical energy (GWh)

Financial year	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop solar PV
2015/16	54,238	50,599	55,752	52,223	50,573	49,094	50,744	52,509
2016/17	55,101	51,323	56,674	53,017	51,262	49,880	51,635	53,506
2017/18	54,538	50,198	56,139	51,918	50,172	48,739	50,925	53,406
2018/19	54,861	50,473	56,381	52,118	50,163	48,764	51,240	54,529
2019/20	54,179	50,039	55,776	51,740	49,248	47,860	50,804	54,449
2020/21	53,415	49,727	54,710	51,140	48,608	47,421	50,107	55,232
2021/22	53,737	49,940	54,744	51,052	48,625	47,405	50,081	56,162
2022/23	52,692	48,906	53,690	49,998	47,422	46,214	49,047	55,714
2023/24	54,827	50,154	55,858	51,272	48,753	47,477	50,251	58,010
2024/25	54,192	50,775	54,983	51,675	48,821	47,306	50,374	59,104

Note:

(1) Source: Powerlink revenue meters.

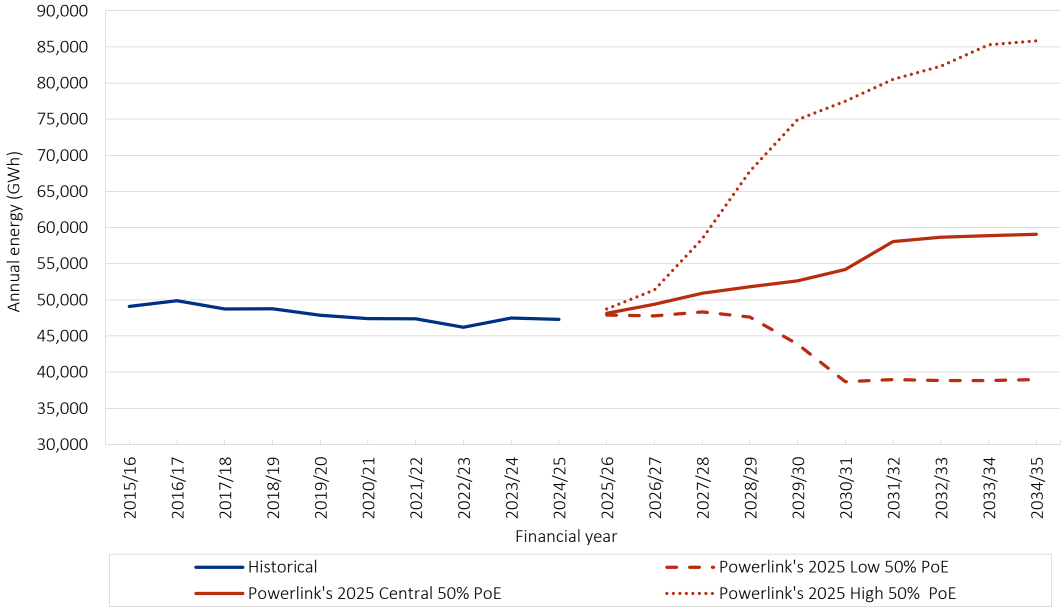
The transmission delivered energy forecasts are presented in Table 2.4.

Table 2.4 Forecast annual transmission delivered energy (GWh)

Financial year	High	Central	Low
2025/26	48,744	48,147	47,879
2026/27	51,371	49,418	47,797
2027/28	58,462	50,926	48,345
2028/29	67,800	51,819	47,633
2029/30	74,940	52,634	43,863
2030/31	77,489	54,215	38,679
2031/32	80,504	58,054	38,976
2032/33	82,320	58,654	38,832
2033/34	85,319	58,890	38,843
2034/35	85,834	59,077	38,966

The historical annual transmission delivered energy from Table 2.3 and the forecast transmission delivered energy for the High, Central and Low scenarios from Table 2.4 are shown in Figure 2.11.

Figure 2.11 Historical and forecast transmission delivered energy



The native energy forecasts are presented in Table 2.5.

Table 2.5 Forecast annual native energy (GWh)

Financial Year	High	Central	Low
2025/26	52,319	52,106	51,671
2026/27	54,576	53,495	51,881
2027/28	61,677	55,033	52,826
2028/29	71,009	55,797	52,762
2029/30	78,155	56,423	51,097
2030/31	80,724	57,107	48,086
2031/32	83,723	60,293	48,157
2032/33	85,543	60,947	48,237
2033/34	88,543	61,178	48,442
2034/35	89,049	61,349	48,646

2.8.3 Summer maximum demand forecast

Historical Queensland summer maximum demand measurements at time of transmission delivered peak are presented in Table 2.6.

Table 2.6 Historical summer maximum demand at time of transmission delivered peak (MW)

Summer	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Transmission delivered corrected to 50% PoE	Native	Native plus solar PV
2015/16	9,154	8,620	9,332	8,850	8,532	8,222	8,050	8,541	9,021
2016/17	9,412	8,856	9,572	9,078	8,694	8,347	8,257	8,731	8,817
2017/18	9,798	9,211	10,015	9,489	9,080	8,789	8,515	9,198	9,602
2018/19	10,010	9,433	10,173	9,666	9,248	8,969	8,488	9,387	9,523
2019/20	9,836	9,283	10,052	9,544	9,056	8,766	8,662	9,255	9,453
2020/21	9,473	8,954	9,627	9,161	8,711	8,479	8,660	8,929	9,256
2021/22	10,058	9,503	10,126	9,624	9,332	9,031	8,876	9,323	9,323
2022/23	9,873	9,363	9,985	9,487	9,202	8,916	9,110	9,413	9,413
2023/24	11,005	10,359	11,136	10,587	9,807	9,429	9,218	11,149	11,149
2024/25	11,144	10,612	11,220	10,751	10,382	9,974	9,529	10,342	10,751

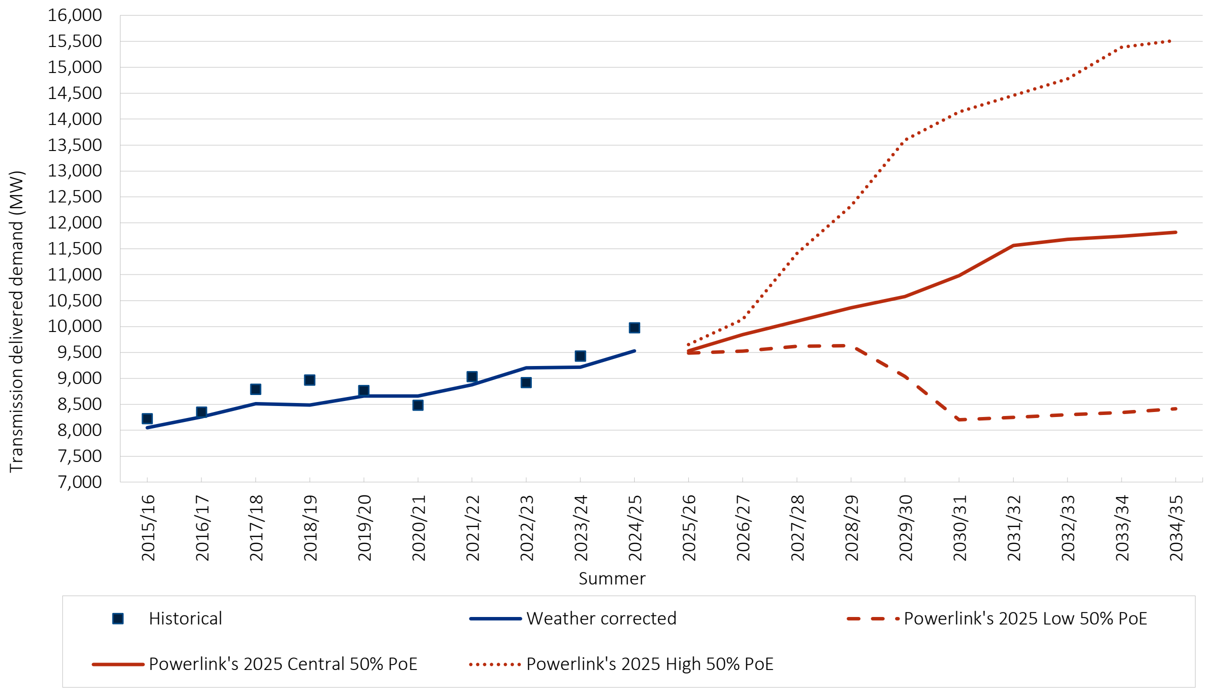
The summer transmission delivered maximum demand forecasts are presented in Table 2.7.

Table 2.7 Forecast summer transmission delivered maximum demand (MW)

Summer	High			Central			Low		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2025/26	9,088	9,653	10,415	8,964	9,529	10,321	8,885	9,487	10,221
2026/27	9,545	10,139	10,936	9,264	9,843	10,651	8,931	9,524	10,257
2027/28	10,800	11,410	12,258	9,510	10,102	10,909	9,019	9,619	10,357
2028/29	11,710	12,330	13,191	9,742	10,360	11,188	9,032	9,631	10,375
2029/30	12,923	13,597	14,524	9,943	10,579	11,430	8,479	9,038	9,733
2030/31	13,457	14,141	15,089	10,330	10,984	11,835	7,697	8,203	8,809
2031/32	13,760	14,457	15,413	10,858	11,561	12,448	7,745	8,247	8,858
2032/33	14,066	14,779	15,755	10,977	11,682	12,582	7,795	8,300	8,911
2033/34	14,634	15,389	16,409	11,043	11,740	12,648	7,844	8,344	8,960
2034/35	14,728	15,516	16,545	11,136	11,817	12,720	7,906	8,413	9,035

The summer historical transmission delivered maximum demands from Table 2.6 and the forecast 50% PoE summer transmission delivered maximum demands for the High, Central and Low scenarios from Table 2.7 are shown in Figure 2.12.

Figure 2.12 Historical and forecast transmission delivered summer maximum demand



2.8.4 Winter maximum demand forecast

Historical Queensland winter maximum demand measurements at time of transmission delivered peak are presented in Table 2.8. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 2.8 Historical winter maximum demand at time of transmission delivered peak (MW)

Winter	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Transmission delivered corrected to 50% PoE	Native	Native plus rooftop solar PV
2016	8,017	7,469	8,176	7,678	7,398	7,176	7,198	7,456	7,456
2017	7,595	7,063	7,756	7,282	7,067	6,870	7,138	7,085	7,085
2018	8,172	7,623	8,295	7,803	7,554	7,331	7,654	7,580	7,580
2019	7,898	7,446	8,096	7,735	7,486	7,296	7,289	7,544	7,544
2020	8,143	7,671	8,320	7,941	7,673	7,483	7,276	7,751	7,751
2021	8,143	7,677	8,279	7,901	7,659	7,472	7,376	7,714	7,725
2022	8,625	8,216	8,701	8,347	8,141	7,921	7,571	8,127	8,127
2023	8,137	7,601	8,223	7,738	7,585	7,399	7,556	7,553	7,553
2024	8,728	8,190	8,728	8,152	8,196	7,970	7,876	7,927	7,927
2025	8,591	8,093	8,615	8,181	8,103	7,876	(1)	7,955	7,955

Note:

(1) The winter 2025 weather corrected demand was not available at time of publication.

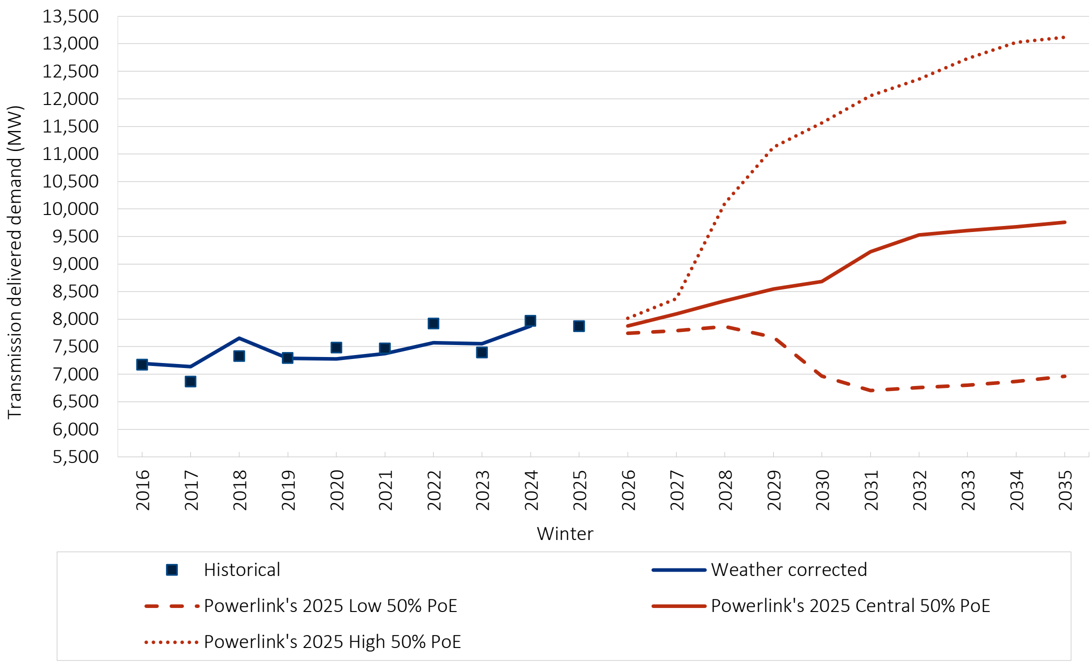
The winter transmission delivered maximum demand forecasts are presented in Table 2.9.

Table 2.9 Forecast winter delivered maximum demand (MW)

Winter	High			Central			Low		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2026	7,797	8,016	8,331	7,662	7,876	8,176	7,505	7,747	8,080
2027	8,151	8,373	8,719	7,881	8,095	8,410	7,553	7,789	8,122
2028	9,856	10,101	10,469	8,110	8,333	8,660	7,632	7,868	8,209
2029	10,855	11,120	11,490	8,309	8,545	8,880	7,430	7,674	8,015
2030	11,282	11,563	11,946	8,431	8,683	9,023	6,722	6,967	7,273
2031	11,758	12,057	12,448	8,965	9,223	9,573	6,514	6,706	6,981
2032	12,051	12,360	12,771	9,249	9,529	9,898	6,549	6,756	7,024
2033	12,397	12,729	13,146	9,323	9,608	9,980	6,577	6,803	7,068
2034	12,685	13,028	13,466	9,389	9,677	10,050	6,626	6,872	7,121
2035	12,770	13,118	13,577	9,460	9,760	10,128	6,704	6,965	7,192

The winter historical transmission delivered maximum demands from Table 2.8 and the forecast 50% PoE summer transmission delivered maximum demands for the High, Central and Low scenarios from Table 2.9 are shown in Figure 2.13.

Figure 2.13 Historical and forecast winter transmission delivered maximum demand



2.8.5 Minimum demand forecast

Historical Queensland minimum demand measurements at time of transmission delivered minimum are presented in Table 2.10.

Table 2.10 Historical minimum demand (MW)

Year	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop solar PV
2016	4,944	4,470	5,101	4,686	4,471	4,336	4,552	4,552
2017	4,791	4,313	4,942	4,526	4,318	4,181	4,389	4,389
2018	4,647	4,165	4,868	4,501	4,143	4,008	4,366	5,572
2019	4,211	3,712	4,441	4,112	3,528	3,370	3,953	5,323
2020	3,897	3,493	4,094	3,767	3,097	3,006	3,675	5,882
2021	3,869	3,480	3,958	3,701	3,043	3,014	3,671	6,804
2022	3,504	3,065	3,617	3,283	2,707	2,597	3,173	6,457
2023	3,490	2,973	3,655	3,277	2,634	2,538	3,181	6,232
2024	3,091	2,647	3,091	2,650	2,650	2,389	2,389	6,741
2025	2,790	2,684	2,886	2,784	2,573	2,239	2,450	5,872

Annual transmission delivered minimum demand forecasts are presented in Table 2.11.

Table 2.11 Forecast annual transmission delivered minimum demand (MW) (1)

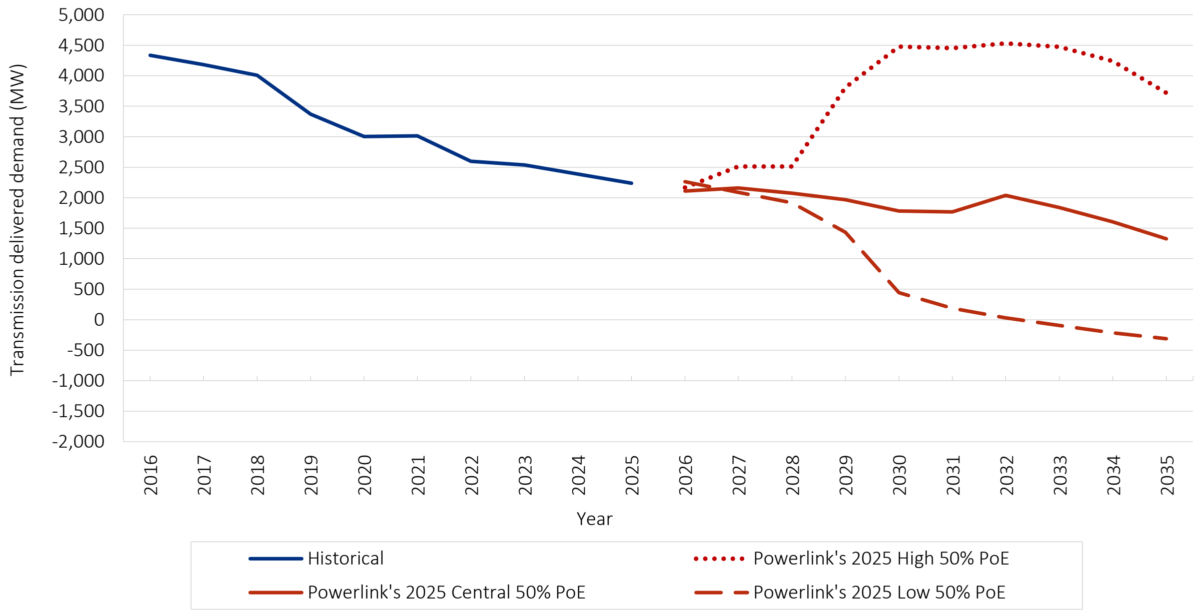
Year	High			Central			Low		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2026	1,885	2,165	2,665	1,809	2,110	2,594	1,871	2,262	2,758
2027	2,053	2,510	2,963	1,710	2,161	2,578	1,682	2,087	2,566
2028	2,212	2,510	3,019	1,608	2,074	2,497	1,514	1,918	2,398
2029	3,497	3,807	4,310	1,496	1,968	2,408	1,038	1,432	1,896
2030	3,959	4,479	4,980	1,311	1,784	2,250	71	442	883
2031	4,046	4,454	4,970	1,430	1,770	2,307	-175	185	594
2032	3,992	4,531	5,082	1,544	2,042	2,525	-336	28	434
2033	3,980	4,475	5,031	1,336	1,839	2,339	-464	-94	312
2034	3,641	4,238	4,822	1,103	1,605	2,115	-547	-216	224
2035	3,106	3,719	4,324	823	1,328	1,843	-608	-312	135

Note:

(1) Forecasts are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but will impact the output of embedded VRE generators and, as a consequence, transmission delivered demand.

The annual historical transmission delivered minimum demands from Table 2.10 and the forecast 50% PoE annual transmission delivered minimum demands for the High, Central and Low scenarios from Table 2.11 are shown in Figure 2.14. The minimum demand forecast does not factor in any market intervention to prevent the grid from becoming insecure under the minimum system load conditions. Market interventions could include directing off embedded non-scheduled generators and directing on grid-scale BESS and Pumped Hydro Energy Storage (PHES) systems to increase demand.

Figure 2.14 Historical and forecast transmission delivered annual minimum demand



2.9 Zone forecasts

Powerlink's 2025 TAPR zone maximum demand forecasts are coincident with the state peak. The 12 geographical zones are defined in Table G.1 and illustrated in Figure G.1 in Appendix G. Each zone experiences its own (non-coincident) maximum demand, which is greater than or equal to that shown in tables 2.13 to 2.15.

Table 2.12 shows the average ratios of zone maximum transmission delivered demand to zone transmission delivered demand at the time of Queensland region maximum delivered demand. These values can be used to multiply demands in tables 2.13 and 2.15 to estimate each zone's individual maximum transmission delivered demand, the time of which is not coincident with the time of Queensland region maximum transmission delivered demand. The ratios are based on historical trends.

Table 2.12 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum delivered demand

Zone	Winter	Summer
Far North	1.16	1.19
Ross	1.61	1.45
North	1.14	1.14
North West	1.02	1.03
Central West	1.01	1.03
Gladstone	1.03	1.02
Wide Bay	1.03	1.20
Surat	1.25	1.22
Bulli	1.05	1.14
South West	1.04	1.24
Moreton	1.01	1.02
Gold Coast	1.04	1.12

Table 2.13 shows the historical and forecast transmission delivered energy for the Central scenario for each of the 12 zones in the Queensland region.

Table 2.13 Annual transmission delivered energy by zone (GWh)

Financial Year	Far North	Ross	North West	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals													
2015/16	1,724	2,944	-	2,876	3,327	10,721	1,272	2,633	1,290	1,224	17,944	3,139	49,094
2016/17	1,704	2,682	-	2,661	3,098	10,196	1,305	4,154	1,524	1,308	18,103	3,145	49,880
2017/18	1,657	2,645	-	2,650	3,027	9,362	1,238	4,383	1,497	1,315	17,873	3,092	48,739
2018/19	1,648	2,338	-	2,621	2,996	9,349	1,198	4,805	1,519	1,376	17,849	3,065	48,764
2019/20	1,594	2,466	-	2,495	2,859	9,303	1,031	5,025	1,580	1,141	17,395	2,971	47,860
2020/21	1,519	2,569	-	2,413	2,813	9,383	970	5,241	1,491	993	16,807	3,222	47,421
2021/22	1,598	2,418	-	2,755	2,776	9,124	904	5,420	1,395	990	17,101	2,924	47,405
2022/23	1,602	2,074	-	2,668	2,783	8,898	898	5,279	1,334	971	16,829	2,878	46,214
2023/24	1,566	2,286	-	2,548	2,866	9,368	951	5,376	1,481	991	17,093	2,948	47,474
2024/25	1,501	2,275	-	2,555	2,807	9,353	953	5,363	1,513	920	17,125	2,941	47,306
Forecasts													
2025/26	1,601	1,985	-	2,624	3,025	9,572	676	4,302	1,648	908	18,289	3,516	48,147
2026/27	1,603	1,803	-	2,447	2,998	10,449	807	4,214	1,558	854	19,071	3,615	49,418
2027/28	1,625	1,904	-	2,451	3,189	10,785	843	4,212	1,540	853	19,794	3,731	50,926
2028/29	1,606	1,900	-	2,466	3,322	11,131	829	4,276	1,510	857	20,128	3,793	51,819
2029/30	1,609	1,924	-	2,495	3,353	11,536	826	4,211	1,515	865	20,438	3,862	52,634
2030/31	1,611	2,195	-	2,797	3,465	12,207	820	4,097	1,473	938	20,690	3,922	54,215
2031/32	1,630	1,923	887	2,487	3,388	15,241	838	4,029	1,424	865	21,318	4,023	58,054
2032/33	1,639	1,848	891	2,398	3,369	15,796	838	3,860	1,390	832	21,714	4,078	58,654
2033/34	1,643	1,813	879	2,357	3,361	15,863	836	3,736	1,358	825	22,075	4,144	58,890
2034/35	1,638	1,793	878	2,326	3,343	15,865	827	3,710	1,349	810	22,341	4,197	59,077

Table 2.14 shows the historical and forecast transmission delivered summer maximum demand for each of the 12 zones in the Queensland region. It is based on the Central scenario and average (50% PoE) summer weather.

Table 2.14 State summer maximum transmission delivered demand by zone (MW)

Financial Year	Far North	Ross	North West	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals													
2015/16	308	392	-	411	443	1,189	214	265	155	231	3,953	661	8,222
2016/17	258	222	-	378	429	1,193	270	421	178	286	3,993	719	8,347
2017/18	304	376	-	413	463	1,102	278	504	183	301	4,147	718	8,789
2018/19	342	339	-	400	484	1,096	285	526	191	312	4,270	724	8,969
2019/20	286	325	-	391	368	1,080	263	610	191	267	4,276	709	8,766
2020/21	254	405	-	431	471	1,111	298	588	165	248	3,894	614	8,479
2021/22	363	441	-	473	518	1,103	269	594	174	253	4,146	697	9,031
2022/23	305	365	-	414	418	1,091	283	547	132	276	4,359	725	8,916
2023/24	294	321	-	423	372	1,098	214	608	177	270	4,907	742	9,429
2024/25	327	443	-	405	475	1,120	297	641	197	255	4,988	824	9,974
Forecasts													
2025/26	348	549	-	523	513	1,182	288	534	181	289	4,271	852	9,529
2026/27	350	577	-	544	529	1,185	296	530	172	300	4,498	861	9,843
2027/28	359	607	-	560	567	1,270	295	548	172	318	4,499	908	10,102
2028/29	367	603	-	564	577	1,284	308	547	169	315	4,699	928	10,360
2029/30	380	585	-	537	563	1,407	310	526	166	301	4,849	955	10,579
2030/31	392	683	-	660	601	1,415	314	511	161	342	4,961	945	10,984
2031/32	391	729	260	703	623	1,422	314	520	159	345	5,113	982	11,561
2032/33	391	641	260	615	619	1,738	330	512	160	327	5,094	995	11,682
2033/34	387	621	260	581	605	1,757	316	479	152	324	5,210	1,048	11,740
2034/35	402	603	260	558	592	1,761	329	468	150	325	5,338	1,032	11,817

Table 2.15 shows the historical and forecast transmission delivered winter maximum demand for each of the 12 zones in the Queensland region. It is based on the Central scenario and average (50% PoE) winter weather.

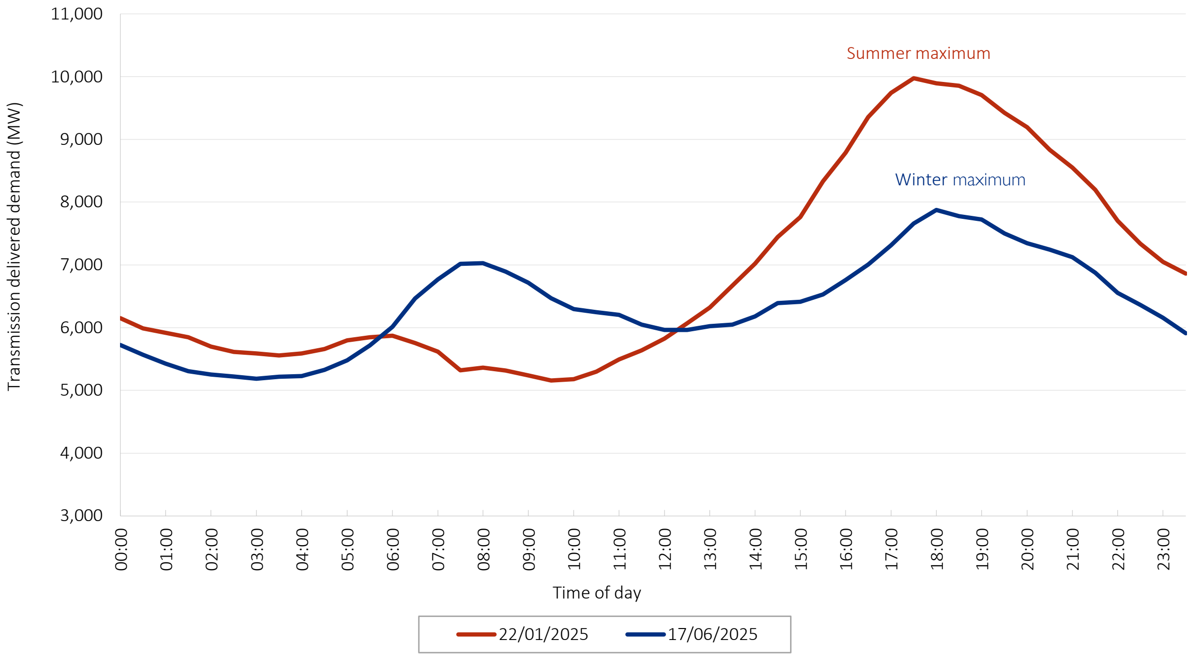
Table 2.15 State winter maximum transmission delivered demand by zone (MW)

Financial Year	Far North	Ross	North West	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals													
2016	226	249	-	370	417	1,242	206	390	181	279	3,079	537	7,176
2017	241	368	-	366	377	1,074	216	513	187	248	2,797	483	6,870
2018	242	366	-	335	439	1,091	235	475	186	336	3,086	540	7,331
2019	234	284	-	362	419	1,037	239	615	195	293	3,078	540	7,296
2020	227	306	-	327	449	1,104	246	531	191	313	3,274	515	7,483
2021	204	296	-	334	383	1,075	250	592	179	339	3,275	545	7,472
2022	230	246	-	322	431	991	280	508	162	360	3,780	611	7,921
2023	217	237	-	352	418	1,069	252	606	167	321	3,225	537	7,399
2024	221	187	-	367	441	1,071	270	473	193	396	3,728	624	7,970
2025	233	329	-	416	457	1,059	247	673	192	324	3,392	555	7,876
Forecasts													
2026	287	380	-	350	398	1,182	238	441	150	215	3,530	704	7,876
2027	288	399	-	364	408	1,185	244	436	142	223	3,699	708	8,095
2028	296	421	-	373	439	1,270	244	452	142	237	3,711	749	8,333
2029	303	417	-	375	447	1,284	254	451	139	234	3,876	766	8,545
2030	312	390	-	340	430	1,407	254	432	136	218	3,980	784	8,683
2031	329	492	-	464	475	1,415	264	429	135	261	4,166	794	9,223
2032	322	588	220	565	509	1,422	259	429	131	280	4,214	809	9,529
2033	322	414	220	381	469	1,738	271	421	131	233	4,190	818	9,608
2034	319	399	220	354	458	1,757	260	395	125	231	4,295	864	9,677
2035	332	386	220	337	449	1,761	271	387	124	233	4,409	852	9,760

2.10 Summer and winter maximum and annual minimum daily profiles

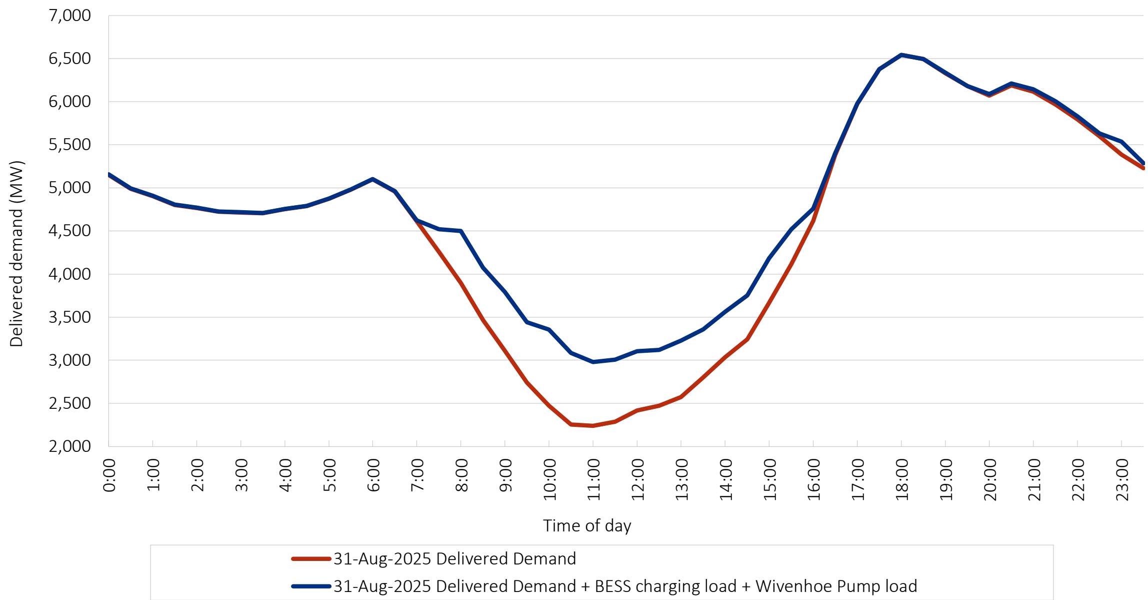
The daily load profiles (transmission delivered) for the Queensland region on the days of summer 2024/25 and winter 2025 maximum demands are shown in Figure 2.15.

Figure 2.15 Daily load profile of summer 2024/25 and winter 2025 maximum transmission delivered demand days



The 2025 annual minimum (transmission delivered) daily load profile for the Queensland region delivered demand plus BESS charging load and Wivenhoe pump load is shown in Figure 2.16. The transmission delivered demand definition excludes the load from pumped hydro and BESS charging load. Adding the BESS and pumped hydro load to the minimum transmission delivered demand demonstrates that there is extra load on the network that assists in avoiding insecure load levels.

Figure 2.16 Daily load profile of 2025 minimum transmission delivered day and minimum delivered demand plus BESS charging load and Wivenhoe pump load (1)



Note:

(1) Based on preliminary meter data up to 18 September 2025.

2.11 Annual load duration curves

The annual historical load duration curves for the Queensland region transmission delivered demand since 2020/21 is shown in Figure 2.17. The graphs illustrate the widening gap between the minimum and maximum demand on the network. Previously, the maximum demand was the cause of concern and where the network limits were being stressed. The network is now facing new challenges due to the rapidly declining minimum demand.

Figure 2.17 Historical transmission delivered load duration curve

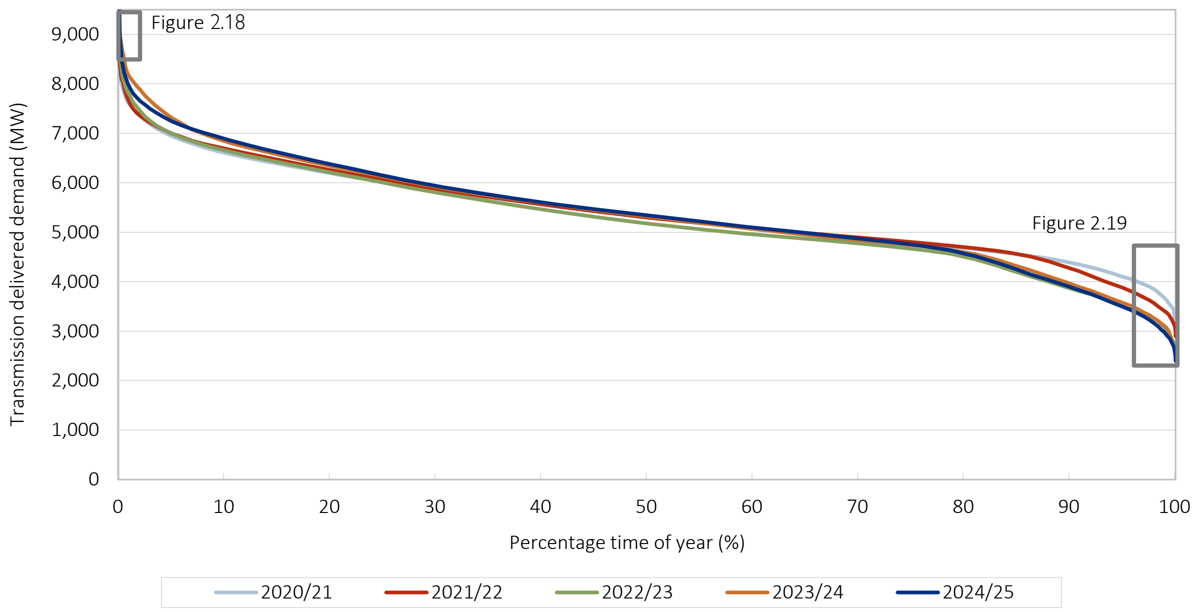


Figure 2.18 Historical transmission delivered load duration curves (95-100%)

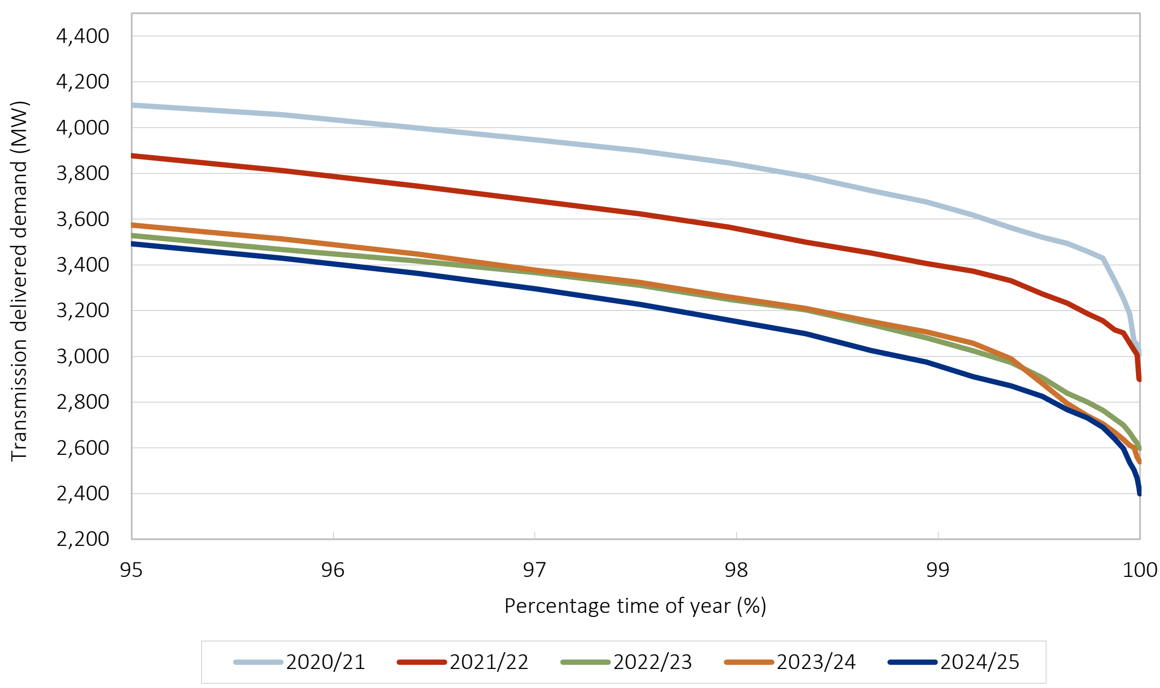
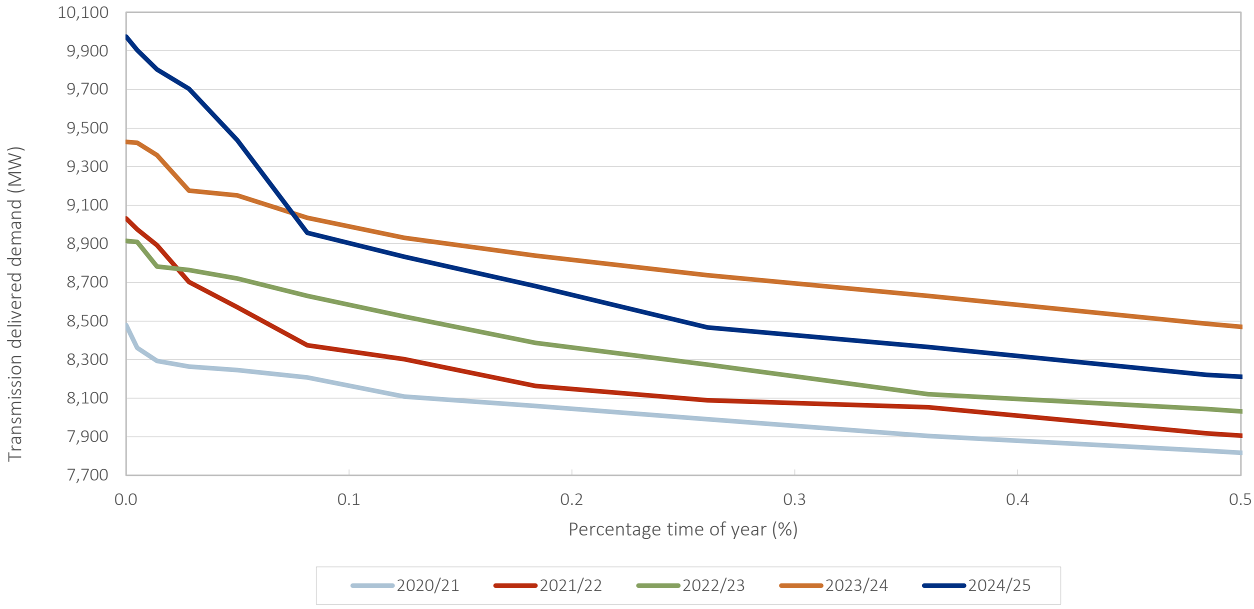


Figure 2.19 Historical transmission delivered load duration curves (0-0.5%)



Power system security services planning

03

03. Power system security services planning

The increased share of generation from inverter-based resources (IBR) is changing the way system security services, such as system strength and inertia, are planned for, delivered and managed. Powerlink is actively planning for and procuring system security services to support the stable operation of the power system in Queensland.

Key highlights

- System security services have traditionally been provided as an inherent characteristic of synchronous generation.
- The need for new approaches to system security services arises because most IBR do not inherently provide all these services.
- The provision of system security services is forecast to be most critical at times of low demand, when fewer synchronous generators are online and inherent support is reduced.
- Changes to roles and responsibilities for planning, procuring and delivering power system security frameworks under the National Electricity Rules (NER) have been made in recent years.
- Powerlink is the System Strength Service Provider (SSSP) for Queensland with specific obligations defined in the NER.
- Powerlink is seeking to deliver system security services that support a safe, reliable and cost-effective power system for Queensland customers.

3.1 Introduction

This chapter provides an outline of how Powerlink is meeting the challenges of delivering system security services, and addresses requirements in the NER for the Transmission Annual Planning Report (TAPR) to provide information on:

- the activities Powerlink has undertaken to make system strength and inertia network services available[1]
- Powerlink's response to the Australian Energy Market Operator's (AEMO) most recent system security reports[2]
- proposed network investment to address system strength requirements[3]
- the modelling methodologies, assumptions and results used by Powerlink to plan activities to meet the System Strength Standard[4]
- the available fault level (AFL) at each system strength node[5]
- the system strength locational factor and corresponding system strength node for each connection point for which Powerlink is the Network Service Provider (NSP)[6].

3.2 System security services

Queensland's power system has historically comprised of synchronous generation such as coal-fired power stations, gas turbines and hydro-electric plants. These large generators inherently provide various system security services, such as voltage regulation, inertia and system strength, as an inherent characteristic of their energy dispatch, supporting stable and reliable power system operation.

The increased contribution of IBR generation sources, particularly solar and wind, can reduce the availability of system security services in the National Electricity Market (NEM), prompting the need for new approaches to the planning and delivery of these services.

Table 3.1 outlines the range of system security services which are needed to operate the power system.

1 National Electricity Rules (NER), clauses 5.20B.4(h)(1) and 5.20C.3(f)(1).
2 NER, clause 5.12.1(b)(3).
3 NER, clause 5.20C.3(g).
4 NER, clause 5.20C.3(f)(2).
5 NER, clause 5.20C.3(f)(3).
6 NER, clause 5.12.2(c)(13).

Table 3.1 System security services

Service	Description
System strength	Sufficient ('protection grade') fault current level for protection operation and a stable voltage waveform
Voltage regulation	Maintaining voltages at acceptable levels and sufficient dynamic voltage support to arrest any changes following contingencies
Frequency control	Maintaining system frequency within acceptable range with ongoing natural variations in load and generation, and sudden step-changes following contingencies
Inertia	Limiting the potential rate of change of system frequency following contingencies
Damping	Damping of power system oscillations so that any disturbances decay at an acceptable rate
Power quality	Control of phase unbalance, voltage harmonics, and flicker
Reserves	Availability of generation reserves or demand side resources to restore system security within 30 minutes following contingencies, and for tracking variations in residual demand throughout the day

The provision of system security services is forecast to be most critical at times of low demand, as fewer synchronous generators can remain online. For example, a 350 megawatt (MW) synchronous generator has a minimum stable load of approximately 140MW. Where multiple synchronous generators are needed to be online to maintain system security, minimum demand required needs to be at least as high as the combined minimum stable load of those generators operating (less any interconnector exports). At the same time, market spot prices are typically suppressed (and frequently become negative) at times of low grid-supplied demand, creating a financial incentive to minimise the number of synchronous generators online. Additionally, low market prices provide a strong signal to maximise load (including the charging of storage), increasing the level of demand. If this occurs frequently, it provides an incentive for the development of new energy storage capacity and load.

During very low load periods, non-scheduled generation may be curtailed (resulting in spilling the available energy) to ensure sufficient demand is available to preserve the minimum levels of synchronous generation required to maintain system security. In extreme cases, the Emergency Backstop Mechanism will be activated by Energy Queensland under direction from AEMO. The mechanism switches off inverter-based energy systems (such as rooftop solar PV with capacity of at least 10 kilovolt amperes) for a short time to maintain system security[7].

Other factors that also affect the provision of system security services relate to the location of synchronous generation plant being online, and include (but are not limited to):

- Network outages, especially those that disconnect Queensland from the NEM, or make this a credible possibility, may require additional system security services to be procured within Queensland.
- Particular generation patterns can cause localised gaps in the availability of system security services in real-time.

There are opportunities for new technologies and non-network solutions to assist with addressing power system security requirements and reduce the need for additional transmission network investment. For example, incentives such as time-of-use tariffs for residential batteries and electric vehicles have the potential to help smooth daily demand profiles and improve the utilisation of the network.

3.3 System security framework

AEMO has responsibility for the forecasting of power system security services. AEMO's annual system security reports assess the need for services across all regions of the NEM, and evaluate requirements for system strength, inertia and Network Support and Control Ancillary Services (NSCAS).

In March 2024, the Australian Energy Market Commission (AEMC) made the Improving Security Frameworks for the Energy Transition Rule which aimed to enhance arrangements to value, procure and schedule system security services in the NEM[8].

7 Queensland Government, Emergency Backstop Mechanism, viewed September 2025.
8 AEMC, Improving Security Frameworks for the Energy Transition, final determination, March 2024, pages 35-37. Prior to the rule change, system strength and inertia services were excluded from the definition of NSCAS under the NER.

3.3.1 Inertia

Inertia is the ability of the system to resist sudden frequency deviations and slow the rate of change of frequency. The energy required to counter significant frequency deviations caused by an imbalance in power supply and demand during a contingency event can come from either the kinetic energy stored in the momentum of synchronous machines or from an instantaneous, rapid and automatic injection of energy from another source (such as synthetic inertia from a battery). Similar to system strength, inertia has traditionally been provided by synchronous generators, and additional remediation is now needed to ensure the power system has sufficient inertia to remain secure.

AEMO is required under the NER to assess whether shortfalls in inertia exist (or are likely to exist) and Transmission Network Service Providers are obliged to use reasonable endeavours to make minimum levels of inertia continuously available[9].

In December 2024, AEMO decreased the previously declared inertia shortfall in Queensland from (up to) 1,660 megawatt seconds (MWs) to 256MWs, in 2027/28[10]. Powerlink understands the primary change in 2024 was an increase in registrations for the one-second Frequency Control Ancillary Services market over the year, which reduces the amount of inertia required during islanded operation of Queensland.

Given the potential for system strength solutions to contribute to inertia, the preferred option for the System Strength Regulatory Investment Test for Transmission (RIT-T) (refer to Section 3.4) may address, either in part or in full, the timing and size of the inertia shortfall.

3.3.2 System strength

System strength is a measure of the ability of the power system to maintain and control a stable voltage waveform at a given location, both during steady state operation and following a disturbance, such as a sudden change in generation or load, or fault on the network[11].

The Efficient Management of System Strength on the Power System Rule, made in October 2021:

- established Powerlink as the SSSP for Queensland
- evolved the 'do no harm' framework which required connecting generators to self-assess their impact on the local network's system strength levels, and self-remediate any adverse impacts
- introduced the System Strength Standard, which requires Powerlink to use reasonable endeavours to plan, design, maintain and operate its network, or make system strength services available to AEMO, from December 2025[12].

Under the new framework, two measures of system strength are defined:

- Minimum level system strength – which maintains the minimum fault level requirements for power system stability (refer to Section 3.5.1)
- Efficient level system strength – which maintains stable voltage waveforms to support future IBR (refer to Section 3.5.2).

3.3.3 Investment drivers

Powerlink is seeking to balance the cost to customers of investing in alternative sources of system security services (such as synchronous condensers) against the potential consequences of insufficient services being available across all operating conditions.

While the costs of these investments may be significant, rapid technological changes such as expanding capabilities of grid-forming Battery Energy Storage Systems (BESS), and procuring services from Pumped Hydro Energy Storage (PHES) systems and gas turbines with clutches, may reduce the need for some solutions over time. In particular, if grid-forming BESS prove to be technically and commercially viable providers of (protection grade) system strength, and are widely deployed, this could reduce the need for Powerlink to invest in other solutions.

However, there are strong drivers to support a prudent and timely approach to investing in proven sources of system security services. Some solutions require long implementation lead times, and delay in investment could result in insufficient system security services increasing the risk of degraded system performance and extended supply interruptions for customers.

Powerlink recognises that these uncertainties cannot be fully resolved through analysis alone, as they depend on factors that are either confidential to market participants or subject to future conditions that are inherently uncertain and evolving.

9 NER, clauses 4.3.4(j) and 5.20B.4(b).
10 AEMO, 2024 Inertia Report, December 2024, page 14.
11 AEMO, System Strength in the NEM Explained, March 2020, page 5.
12 AEMC, Efficient Management of System Strength on the Power System, final determination, October 2021, page 13; NER, clauses 5.20C.3(a) and S5.1.14(b).

Table 3.2 System strength factors subject to significant uncertainty

System strength factor	Nature of uncertainty
Reduction in minimum demand level	The reduction in minimum demand is challenging to forecast because it depends on complex interactions of weather, government policy (e.g. incentivising residential batteries), customer behaviours and timing of new load developments (1).
Timing of coal withdrawal	This includes both generator retirements as well as the possibility some units may modify their operation, reducing the number of units online at any given time. Already, there is a clear trend for fewer units to be available at times of low demand, as generators undertake their maintenance programs.
Location of coal withdrawal	Queensland's transmission network spans a vast geographic area, and certain system services, such as system strength, must be supplied locally. Therefore, there is also a dependency on how operational generators are distributed.
Potential for compound contingencies	Whilst planning focusses on credible contingencies (things that could happen), it is nevertheless important that the system has emergency mechanisms in place to ensure that the power system can recover from non-credible contingencies (rare and severe events).

Note

(1) Refer to Section 2.1.1 for detail on the difficulties of forecasting demand.

To address this need and associated uncertainties, Powerlink's strategy to discharge its responsibilities to plan for and make system security services available includes:

- pursuing a complementary mix of different technologies to address requirements, as outlined in Powerlink's System Strength RIT-T (refer to Section 3.4)
- timing the investment in solutions to anticipate withdrawal of generation, while preserving flexibility to invest in/or procure further solutions over time
- working with the Queensland Government and Energy Queensland (as owner of the Energex and Ergon Energy distribution networks) to explore ways to enhance Queensland's operational tools to maintain system security during periods of low operational demand.

3.4 Activities to meet inertia and system strength requirements

A range of technologies, including synchronous condensers, grid-forming BESS, and PHES systems capable of operating in synchronous condenser mode can deliver system strength services. Gas turbines with clutches, which enable them to operate in synchronous condenser mode, can also provide these services largely without disrupting their energy dispatch.

In June 2025, Powerlink concluded a RIT-T to address system strength requirements in Queensland from December 2025. The preferred option in the RIT-T included:

- nine synchronous condensers across Central Queensland and Southern Queensland by June 2034
- contracting with a range of synchronous generation units in Southern and Northern Queensland for minimum level requirements
- contracting for grid-forming BESS in Southern, Central and Northern Queensland for efficient level requirements[13].

Since finalising the System Strength RIT-T, Powerlink has commenced procurement activities for network synchronous condensers in Central Queensland and is pursuing non-network solutions for Southern, Central and Northern Queensland. The location, timing and expected cost of the network synchronous condensers are still being finalised.

To maintain flexibility, Powerlink has committed to investing in or contracting with a small number of synchronous condensers, while leveraging RIT-T reopening triggers to pivot to new (protection grade) system strength solutions as they become available. Powerlink continues to engage with a range of potential proponents of non-network solutions for system strength and is assessing the potential for grid-forming BESS to address minimum system strength requirements.

[13] Powerlink, Addressing System Strength Requirements in Queensland from December 2025, Project Assessment Conclusions Report, June 2025, page 18.

Indicative costs for non-network solutions were included in the RIT-T cost-benefit assessment. However, these costs did not influence the identification of the preferred option as they are treated as a revenue transfer between energy market participants under the RIT-T framework[14]. Actual costs proposed by non-network proponents during or following the RIT-T process are commercially sensitive and therefore not disclosed by Powerlink.

If inertia requirements are not met by resources invested in or contracted with through the System Strength RIT-T, a separate RIT-T may be required to procure services, or Powerlink may initiate a new RIT-T to meet system strength and inertia needs concurrently.

3.5 System strength modelling

3.5.1 Minimum level requirements

In December 2024, AEMO updated minimum system strength requirements for the NEM.

Table 3.3 shows, for each system strength node, the pre-contingent minimum fault level, and minimum fault level expected 99.87% of the time from 2024/25 to 2027/28.

Table 3.3 AEMO minimum three phase fault level, December 2024

System Strength Node	Parameter	Minimum three phase fault level current (MVA), financial year ending			
		2024/25	2025/26	2026/27	2027/28
Gin Gin	Pre-contingent	2,800	2,800	2,800	2,800
	Projected 99.87% of time	3,150	3,155	3,088	2,877
Greenbank	Pre-contingent	4,350	4,350	4,350	4,350
	Projected 99.87% of time	4,513	4,534	4,199	4,473
Lilyvale	Pre-contingent	1,400	1,400	1,400	1,400
	Projected 99.87% of time	1,400	1,400	1,295	1,247
Ross	Pre-contingent	1,350	1,350	1,350	1,350
	Projected 99.87% of time	1,350	1,350	1,350	1,350
Western Downs	Pre-contingent	4,000	4,000	4,000	4,000
	Projected 99.87% of time	4,121	4,150	3,827	4,078

Note:

(1) Source: AEMO, 2024 System Strength Report, December 2024, pages 29-33.

AEMO indicated that shortfalls at the Greenbank, Lilyvale and Western Downs nodes across 2026/27 and 2027/28 were primarily linked to decreased energy exports to New South Wales (NSW) following the delayed retirement of Eraring Power Station in NSW. In AEMO's modelling, the delayed retirement resulted in fewer thermal units expected to be online in Queensland, and lower fault levels than previously projected[15].

The number of coal generating units in service at any point in time in Queensland is a primary consideration for Powerlink's ability to meet minimum system strength requirements. There are currently 22 coal generating units in Queensland, of which 14 are in Central Queensland and eight are in Southern Queensland. To provide sufficient system strength, in Southern Queensland four units are required to be online at all times, and in Central Queensland six units are required to be online at all times. In Northern Queensland two services are required to be online at all times.

For the System Strength RIT-T, Powerlink adopted a probabilistic approach to assess the likelihood of maintaining adequate system strength across the grid. This analysis incorporated coal retirement projections and their impact on fault levels and stability, based on AEMO's 2024 Integrated System Plan forecasts. From 2025 to 2030, existing synchronous generation in Southern, Central, and Northern Queensland is expected to largely meet minimum system strength requirements in the early years. However, in later years, alternative synchronous technologies, such as synchronous condensers, clutched gas turbines, and pumped hydro, will likely be needed to replace retiring generation.

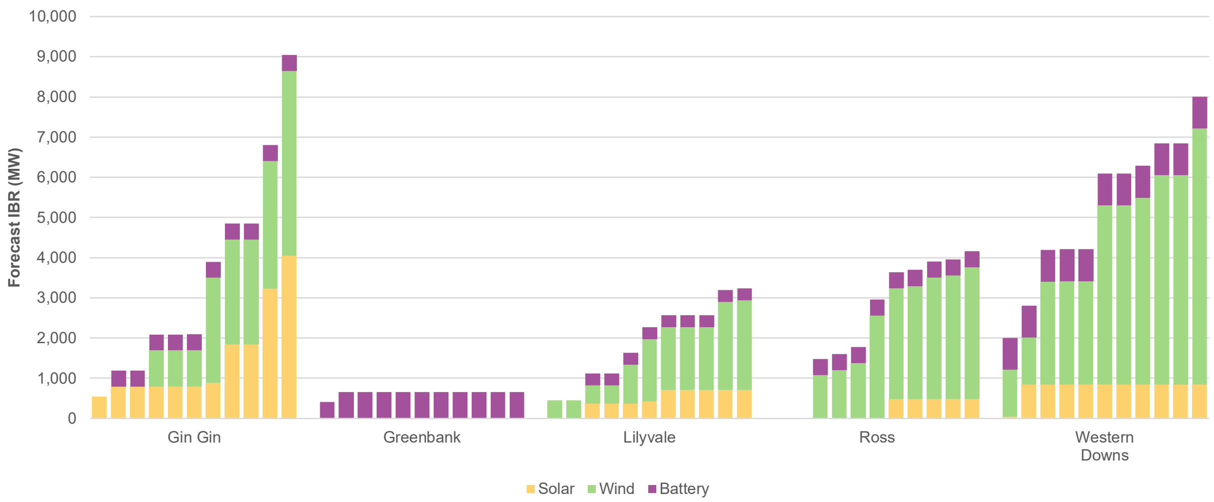
14 AER, The Efficient Management of System Strength Framework, guidance note, December 2024, page 23.
15 AEMO, 2024 System Strength Report, December 2024, page 25.

To address uncertainty in emerging technologies, the RIT-T has been designed with flexibility, allowing a shift to solutions such as gas turbines with clutches or grid-forming BESS if they become technically and commercially viable, while still advancing near-term investments to mitigate system security risks.

3.5.2 Efficient level requirements

The AEMO 2024 System Strength Report also included updated forecasts of IBR generation for Queensland over the 11-year period from 2024/25.

Figure 3.1 AEMO 11-year forecast of level and type of IBR at system strength nodes, December 2024



Notes:

(1) Forecasts excluded existing IBR.

(2) Source: AEMO, 2024 System Strength Report, December 2024, page 28.

At an aggregate level, the 2024 forecast shows higher IBR from 2024/25 to 2032/33 than previous forecasts from 2022 and 2023. Consistent with earlier forecasts, the majority of growth (in terms of megawatts) in the 2024 forecast is for wind projects[16].

Powerlink has created an electromagnetic transient modelling (EMT) simulation model that covers Far North Queensland to the Hunter Valley in New South Wales. The model features detailed representations of all transmission connected variable renewable energy, synchronous generators, BESS and dynamic voltage control plant. The model allows Powerlink to conduct system strength assessments for generator connections.

As part of the System Strength RIT-T, Powerlink mapped its market intelligence of connection applications and enquiries against the forecast provided in AEMO's System Strength Reports. Most projects are choosing to self-remediate their system strength impact. Subsequently, Powerlink performed detailed EMT studies to assess system strength requirements, focussing on both the minimum level and efficient level of system strength support needed for the existing and projected IBR generation in Queensland over the 2025 to 2030 planning horizon.

All inverter-based plants connecting to Powerlink's network must undergo a Full Impact Assessment (FIA) or stability assessment using an EMT model. This analysis is essential to identify any unstable interactions with other generators or voltage control equipment. The assessment follows AEMO's System Strength Impact Assessment Guidelines (SSIAG), which ensures any negative impacts on system strength are addressed as part of the connection application process. Further details on the assessment and modelling requirements are available in the SSIAG and AEMO's Power System Model Guidelines.

3.6 Available fault level as indicator of system strength

While AFL has traditionally been used as a proxy for system strength, it is increasingly recognised as insufficient in modern power systems dominated by IBRs. AFL quantifies the fault current available at a node, but does not capture broader system strength attributes such as the ability to maintain and control voltage waveforms during steady-state and post-disturbance conditions.

16 See AEMO, 2022 System Strength Report, December 2022, page 39; AEMO, 2023 System Strength Report, December 2023, page 27.

AFL also does not account for the dynamic behaviour of the system, including transient and small-signal stability, or the operational viability of protection systems and voltage control devices under low fault level conditions.

Moreover, technologies such as grid-forming BESS can provide system strength without contributing high fault current, further decoupling AFL from actual system resilience. Therefore, relying solely on AFL risks overlooking critical aspects of system operability and stability in a high-IBR environment.

Powerlink considers a FIA the only technically prudent method to assess the dynamic performance of connecting plant under a wide range of network conditions and contingencies to ensure compliance with clause 5.3.4A of the NER. As such, a FIA is a necessary part of the application to connect process.

3.7 System strength locational factors and nodes

System strength locational factors are part of the formula for system strength charges. The NER requires Powerlink to list the system strength locational factor for each connection point for which Powerlink is the NSP, and the corresponding system strength node[17]. System strength locational factors and nodes are included in Appendix I and shown in the TAPR Portal.

[17] NER, clause 5.12.2(c)(13).

Non-network solutions

04

The use of non-network solutions is essential to provide safe, reliable and cost-effective transmission services for customers. This chapter discusses Powerlink's approach and process for engaging with non-network solution providers and provides a summary of potential non-network solution opportunities anticipated to become available over the next five years.

Key highlights

- Non-network solutions can assist to address network needs such as inertia, system strength, network support and control ancillary services (NSCAS) and voltage control.
- Non-network solutions, in part or in full, may also contribute to a network development strategy by maintaining a balance between reliability and the cost of transmission services for customers.
- Interested parties are encouraged to contact NetworkAssessments@powerlink.com.au to discuss non-network solutions, and/or to become a member of Powerlink's Non-network Engagement Stakeholder Register.

4.1 Introduction

Non-network solutions can assist to address network needs such as inertia, system strength, NSCAS and voltage control. In the past, Powerlink has implemented a range of non-network solutions in various areas in Queensland to assist, support or augment the power transfer capability of the high voltage transmission network.

More recently, Powerlink has entered into agreements for reactive power support in Southern Queensland, and for system strength services in Northern Queensland. Powerlink is also negotiating with a number of proponents of non-network solutions to address system strength requirements in Queensland from December 2025[1].

This chapter discusses Powerlink's approach and process for engaging with non-network solution providers, and identifies potential non-network solution opportunities anticipated to become available over the next five years[2].

4.2 Increasing opportunities for non-network solutions

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the National Electricity Rules (NER). For a given network limitation or potential asset replacement, the viability and an indicative specification of non-network solutions are first introduced in the Transmission Annual Planning Report (TAPR) and TAPR Templates. As the identified need date approaches and detailed planning analysis is undertaken, further opportunities are explored in the consultation and stakeholder engagement processes undertaken as part of the Regulatory Investment Test for Transmission (RIT-T).

Powerlink is committed to genuine engagement with providers of non-network solutions and the implementation of these solutions where technically feasible and economic to:

- address inertia, system strength, voltage control and NSCAS requirements
- address future network limitations or address the risks arising from ageing assets remaining in-service within the transmission network
- complement network developments as part of an integrated solution to deliver an overall network development strategy
- provide demand management and load balancing.

Potential non-network solution opportunities within the next five years are described in Table 4.1.

4.3 Non-network Engagement Stakeholder Register

Powerlink uses a Non-network Engagement Stakeholder Register to convey the details of potential non-network solution opportunities directly to non-network solution providers. The register is comprised of a variety of interested stakeholders who have the potential to offer network support and/or system security services through alternate technologies, existing and/or new generation or demand side management initiatives (either as individual providers or aggregators).

More information on potential non-network solutions is available on Powerlink's website, including details regarding current RIT-T consultations and Powerlink's Network Support Contracting Framework.

Interested parties are encouraged to contact NetworkAssessments@powerlink.com.au to become a member of the register.

1 Refer Chapter 3 for detail on Powerlink's role as System Strength Service Provider for Queensland.
2 National Electricity Rules (NER), clauses 5.12.1(b)(6) and 5.12.2(c)(5)(vi).

Table 4.1 Potential non-network solution opportunities within the next five years

Potential project	Indicative cost ($million (m)) (1)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Substation - transformers					
Full replacement of secondary systems associated with the static VAr compensator (SVC) at Strathmore	$24m	North	Potential non-network solutions would need to provide dynamic voltage support of up to 260 megavolt-amperes reactive (MVAr) capacitive and 80MVArs inductive.	December 2029	Section 5.5.3
Replacement of the existing 275/110kV transformer at South Pine	$16m	Moreton	Potential non-network options would need to provide supply to north Brisbane load area of up to 165 megawatts (MW) at peak demand times and up to 1,350 megawatt hours (MWh) a day.	June 2030	Section 5.7.5
Replacement of the existing 110/33/11kV transformer at Tennyson	$11m	Moreton	Potential non-network options would need to provide supply to the Tennyson area of up to 190MW at peak demand times and up to 2,000MWh a day.	June 2028	Section 5.7.5
Replacement of the secondary systems, thyristor valve control systems, and cooling control systems for the SVC installed at Greenbank Substation	$23m	Moreton	Potential non-network options would need to provide voltage control and stability services for the transmission network within the greater south-east Brisbane area, and provide stability and power system dampening services more broadly for the high voltage transmission network.	June 2030	Section 5.7.5

Note:

(1) Indicative cost is for the most likely network option.

Future network requirements

05

05. Future network requirements

This chapter focuses on potential investments required on the transmission network within the first five years of the 10-year outlook period for the Transmission Annual Planning Report (TAPR). It includes information on forecast network limitations, the management of assets and network risks, Regulatory Investment Tests for Transmission (RIT-Ts), Priority Transmission Investments (PTIs), upcoming programs of work, and actionable projects relevant to Queensland referenced in the 2024 Integrated System Plan (ISP).

Key highlights

- Powerlink's regulated capital expenditure program of work will continue to focus on risks arising from the condition and performance of existing aged assets, as well as emerging limitations in the capability of the network.
- Powerlink's approach to investment decision making includes assessing whether an enduring need exists for assets and investigating alternate network configuration opportunities, and/or non-network solutions where feasible, to manage asset and network risk.
- Powerlink is addressing system strength and inertia limitations identified by the Australian Energy Market Operator (AEMO) within the five-year outlook period.
- Powerlink is working with AEMO and other stakeholders on actionable ISP projects and the Gladstone Project.
- Renewal of secondary systems assets will continue to be a key focus for regulatory consultations in the coming year.
- Local and global demand for resources that are essential for transmission projects continues to put upward pressure on costs and extend equipment delivery timeframes. Powerlink is actively seeking to mitigate these pressures to drive value for customers.
- Powerlink will continue to implement changes to the timing, scope and bundling of proposed transmission line refit works to maximise the potential for more cost-effective solutions as recommended in its Asset Reinvestment Review, concluded in June 2023.
- Powerlink is continuing with the development and roll out of the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events.

5.1 Introduction

Powerlink is actively monitoring the changing outlook for the Queensland region of the National Electricity Market (NEM), including the integration of generation and energy storage in future transmission plans. These plans include:

- non-network solutions
- reinvesting in assets to extend their technical service life
- determining optimal locations for new generators
- replacing existing assets with assets of a different type, configuration or capacity
- investing in assets to maintain planning standards and support efficient market outcomes
- removing some assets without replacement where there is no longer an enduring need.

The National Electricity Rules (NER) requires the TAPR to include a forecast of constraints and inability to meet the network performance requirements set out in Schedule 5.1 of the NER, or relevant legislation or regulations, over one, three and five years[1]. The TAPR must also provide estimated load reductions that would defer forecast limitations for a period of 12 months and state any intent to issue request for proposals for augmentation, replacement of network assets or non-network alternatives[2].

Further, the TAPR is required to be consistent with the Australian Energy Regulator's (AER) TAPR Guidelines, and include information pertinent to all proposed:

- augmentations to the network and replacements of network assets
- network asset retirements or asset de-ratings that would result in a network constraint in the 10-year outlook period[3].

1 National Electricity Rules (NER), clause 5.12.2(c)(3).
2 NER, clause 5.12.2(c)(4).
3 NER, clauses 5.12.2(c), (c)(5), and (c)(1A).

This chapter on proposed future network developments contains:

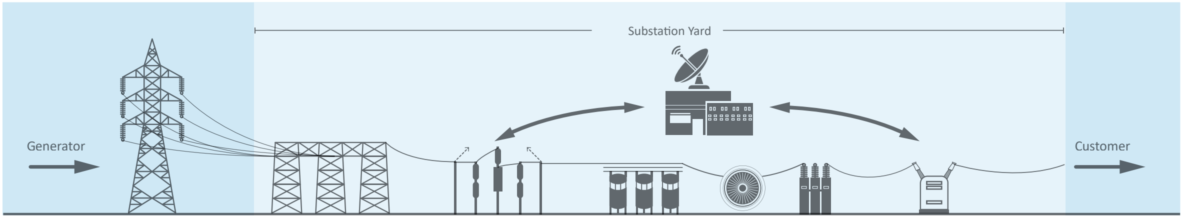
- information regarding assets reaching the end of their technical service life and options to address the risks arising from ageing assets remaining in service, including asset reinvestment, non-network solutions, potential network reconfigurations, asset retirements or de-ratings[4]
- identification of emerging future limitations[5] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months[6]
- a statement of intent to issue requests for proposals, typically undertaken through the RIT-T consultation process, for the proposed augmentation of the transmission network, replacement of ageing network assets, or non-network alternatives, identified as part of the annual planning review[7]
- a summary of network limitations over the next five years[8]
- a table summarising possible connection point proposals
- information on how proposed augmentations and the replacement of network assets relate to AEMO's most recent ISP[9].

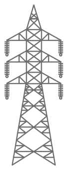
Where appropriate, all transmission network, distribution network or non-network alternatives are considered as options for investment. Submissions for non-network alternatives to proposed investments are invited by emailing NetworksAssessment@powerlink.com.au.

The functions performed by the major transmission network assets discussed in this chapter are illustrated in Figure 5.1.

4 See Table A.1 in Appendix A for a description of planning options.
5 Identification of forecast limitations in this chapter does not mean that there is an imminent supply reliability risk. The NER requires identification of limitations which are expected to occur some years into the future, assuming that demand for electricity is consistent with the forecast in this TAPR.
6 NER, clause 5.12.2(c)(4)(iii).
7 NER, clause 5.12.2(c)(4)(iv).
8 NER, clause 5.12.2(c)(3).
9 NER, clause 5.12.2(c)(6).

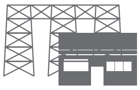
Figure 5.1 Functions of major transmission assets





Transmission line

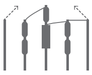
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



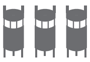
Substation

A substation, which is made up of primary plant, secondary systems, telecommunications equipment and buildings, connects two or more transmission lines to the transmission network and usually includes at least one transformer at the site.

A substation that connects to transmission lines, but does not include a transformer, is known as a switching station.

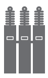


- Substation bay
  A substation bay connects and disconnects network assets during faults and also allows maintenance and repairs to occur. A typical substation bay is made up of a circuit breaker (opened to disconnect a network element), isolators and earth switches (to ensure that maintenance and repairs can be carried out safely), and equipment to monitor and control the bay components.



- Static VAr Compensator (SVC)
  A SVC is used where needed, to smooth voltage fluctuations, which may occur from time-to-time on the transmission network. This enables more power to be transferred on the transmission network and also assists in the control of voltage.

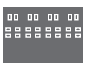
- Synchronous condenser
  A synchronous condenser is a large rotating machine connected to the transmission network with no driving force (spins freely). It is similar to a synchronous generator but does not produce energy. It helps the power system with voltage control, system strength, and inertia.



- Capacitor Bank
  A capacitor bank maintains voltage levels by improving the 'power factor'. This enables more power to be transferred on the transmission network.

- Transformer
  A transformer is used to change the voltage of the electricity flowing on the network. At the generation connection point, the voltage is 'stepped up' to transport higher levels of electricity at a higher voltage, usually 132kV or 275kV, along the transmission network. Typically at a distribution point, the voltage is 'stepped down' to allow the transfer of electricity to the distribution system, which operates at a lower voltage than the transmission network.

- Reactor
  Reactors may be connected directly to a transmission line or a bus at the substation. Line reactors are used to limit the remote end voltage of a long high voltage line when energising (and carrying no load). Bus reactors are typically higher rated and used especially during light load conditions to avoid high voltages which may occur on the network.



Secondary systems

Secondary systems equipment assists in the control, protection and safe operation of transmission assets that transfer electricity in the transmission network.

Telecommunication systems

Telecommunication systems are used to transfer a variety of data about the operation and security of the transmission network including metering data for AEMO.

5.2 Forecast network limitations

5.2.1 Forward planning

Powerlink's forward planning aims to allow adequate time to identify emerging limitations and to implement appropriate network and/or non-network solutions to maintain transmission services to meet the planning standard in our Transmission Authority[10].

Emerging limitations may be triggered by thermal plant ratings (including fault current ratings), protection relay load limits, voltage stability and/or dynamic stability. Appendix I lists the indicative maximum short circuit currents and fault rating of the lowest rated plant at each Powerlink substation and voltage level. The maximum short circuit currents take into account the committed transmission projects listed in Chapter 8 and existing and committed generation listed in Chapter 6.

Based on Powerlink's Central scenario load forecast (refer to Chapter 2), Queensland's transmission delivered maximum demand is expected to have steady growth with an average annual increase of 2.2% per annum over the next 10 years[11].

Notwithstanding network limitations which may result from new loads, such as in the Gladstone zone, Powerlink does not anticipate undertaking any significant augmentation works during the 10-year outlook period based on load growth alone. However, the changing generation mix (and associated peak to average production ratios of variable renewable energy (VRE) generation) may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints, including the effects of falling minimum demand, holistically with the emerging condition-based drivers as part of the planning process and in conjunction with the most recent ISP (refer to Chapter 7).

Projects that could be triggered by the commitment of large mining, metal processing and industrial loads, and for the electrification of existing loads, are also discussed in Chapter 7.

5.2.2 Forecast network limitations within the next five years

Table 5.1 summarises limitations in the five-year period identified in AEMO's latest System Security Reports.

Table 5.1 Limitations in the five-year outlook period

Limitation	Zone	Reason for anticipated limitation	Time limitation may be reached: 1-year outlook (2025/26)	Time limitation may be reached: 3-year outlook (up to 2028/29)	Time limitation may be reached: 5-year outlook (up to 2030/31)	TAPR Reference
System strength shortfalls	Moreton, Central West and Surat zones	AEMO identified system strength shortfalls December 2024	—	Shortfalls at Greenbank, Lilyvale and Western Downs nodes (1)	—	Section 3.4
Inertia shortfall	Statewide	AEMO identified inertia shortfall December 2024	—	In 2027/28 (2)	—	Section 3.4

Notes:

(1) Refer to AEMO's December 2024 System Strength Report.

(2) AEMO's December 2024 Inertia Report indicated the previously declared inertia shortfall had decreased in magnitude to 256 megawatt seconds in 2027/28.

Based on AEMO's Step Change scenario forecast there are no other network limitations forecast to occur in Queensland in the next five years[12].

10 See Appendix A for discussion of Powerlink's approach to maintaining compliance with its Transmission Authority.
11 Refer to Table 2.2.
12 Refer to NER Clause 5.12.2(c)(3).

5.2.3 Forecast network limitations beyond five years

The timing of forecast network limitations may be influenced by a number of factors, such as:

- load growth
- industrial developments (including electrification of existing industrial processes)
- new and retiring generation
- the planning standard in Powerlink's Transmission Authority
- joint planning with other Network Service Providers (NSP).

Based on Powerlink's Central scenario forecast, there are a small number of areas where network limitations are forecast to emerge due to load growth within the 10-year forecast period.

Gladstone

Load growth in the Gladstone zone, together with the potential retirement of the Gladstone Power Station, requires Powerlink to invest in the network (refer to Section 5.6.2).

Northern Bowen Basin

Network limitations are forecast to exceed Powerlink's reliability obligations in the Northern Bowen Basin due to load growth by the end of the 10-year forecast period (refer to Section 5.5.3). Powerlink will consider this emerging limitation, together with the potential electrification load in the Northern Bowen Basin (refer to Section 7.2.2), emerging condition-based drivers, and non-network developments to understand the most economic development. Network solutions may include advancing condition-based rebuild or a more incremental targeted investment such as flow control devices on the existing assets.

Edmonton

Load-driven limitations are forecast to occur at the Edmonton 132/22kV Substation and the 22kV distribution network supplying the Gordonvale area by the end of the 10-year period. Joint planning has identified that establishing a new 132/22kV substation is the preferred network solution south of Cairns. The new Powerlink substation would be supplied via a cut-in to Powerlink's 132kV circuit between Innisfail and Edmonton substations (Merinda area). Due to changing land usage and constraints, the easement and substation site must be acquired ahead of the identified need.

Loganlea

Load-driven limitations are forecast to occur by the end of the forecast period on Energy Queensland's 110kV feeders supplying the Jimboomba and Yarrabilba area and associated 275/110kV transformation capacity at Powerlink's Loganlea Substation. Joint planning has identified establishing a new 275/110/33kV substation as the preferred network solution (Yarrabilba area). This substation will initially cut into the existing 275kV double circuit between Greenbank and Molendinar substations. Again, due to changing land usage and constraints, the easement and substation site must be acquired ahead of the identified need arising.

5.3 Consultations

Consultation processes for proposed transmission investments are conducted via RIT-Ts, Expressions of Interest (EOI) or Funded Augmentations under the NER[13].

All consultation documents are published and made available on Powerlink's website.

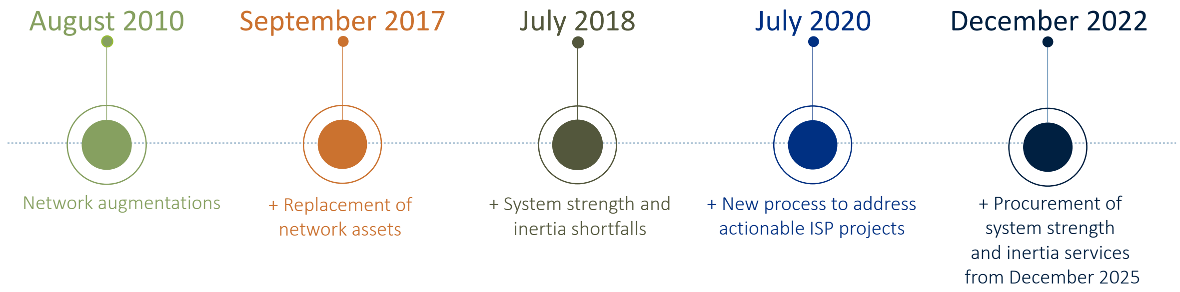
5.3.1 RIT-T Consultation Process

Since the RIT-T process commenced in 2010, the requirements to call for proposals for transmission investments over the RIT-T cost threshold (currently $8 million) have extended from augmentations to the network to address a range of other transmission investment needs, including for system strength and inertia services[14].

13 Powerlink has not commenced or completed any Funded Augmentations since publishing the 2024 TAPR.

14 For actionable ISP projects, the RIT-T consultation process is undertaken according to rule 5.16A of the NER. For investments that are not actionable ISP projects, clause 5.16.4 of the NER applies. The NER, clauses 5.15.3(a) and (b)(2), set the RIT-T threshold at $5 million. The AER's latest cost threshold review increased the value to $8 million for three years from 1 January 2025. For a brief discussion of the application of the RIT-T framework to system security services, see Tim Nelson et. al., National Electricity Market Wholesale Market Settings Review, draft report, August 2025, page 176.

Figure 5.2 Expansion of the application of the RIT-T process for proposed transmission network investments



The majority of RIT-T consultations undertaken by Powerlink relate to projects that are not actionable ISP projects.

Figure 5.3 RIT-T consultation process for projects that are not actionable ISP projects

5.3.2 Completed and current consultations – proposed transmission investments

Powerlink completed one PTI assessment since publishing the 2024 TAPR, being for the Gladstone Project. The PTI assessment was undertaken via modifications to the RIT-T framework[15].

Powerlink has completed two RIT-T consultations since publication of the 2024 TAPR.

Table 5.2 RIT-T consultations completed since publication of the 2024 TAPR

Consultation
Maintaining Reliability of Supply to Mansfield (April 2025)
Addressing System Strength Requirements in Queensland from December 2025 (June 2025)

Table 5.3 RIT-T consultations underway (as at 30 September 2025)

Consultation	TAPR Reference
Maintaining Reliability of Supply to Kamerunga, Cairns and Northern Beaches Area	Section 5.5.1
Maintaining Reliability of Supply and Addressing Condition Risks at Ingham South	Section 5.5.2
Addressing the Risk of Premature Current Transformer Failures in Queensland	Section 5.8.2

15 Powerlink, Gladstone Project: Candidate Priority Transmission Investment Assessment, final assessment report, June 2025, pages 73-76.

5.3.3 Future consultations – proposed transmission investments

Anticipated consultations

Powerlink's capital expenditure program of work in the 10-year outlook period will focus on investment in the transmission network to manage the risks arising from ageing assets remaining in service. These emerging risks are discussed in sections 5.5 to 5.7. Table 5.4 summarises consultations Powerlink anticipates undertaking within the next 12 months under the RIT-T to address either the proposed investment in a network asset or limitation.

Table 5.4 Anticipated consultations (12 months to October 2026)

Consultation (1)	TAPR Reference
Maintaining Reliability of Supply at Chalumbin	Section 5.5.1
Addressing the Static VAr Compensator (SVC) Secondary Systems Condition Risks at Strathmore	Section 5.5.3
Addressing the Secondary Systems Condition Risks at Middle Ridge	Section 5.7.4
Maintaining Power Transfer Capability and Reliability of Supply at Tennyson	Section 5.7.5
Managing the Risk of Specific 275kV Capacitive Voltage Transformers Failures	Section 5.8.2

Note:

(1) The anticipated consultations listed in Table 5.4 reflect the RIT-T status as of 30 September 2025.

Actionable and future ISP projects

The 2024 ISP identified three projects in Queensland as requiring action by Powerlink:

- Gladstone Grid Reinforcement (now referred to as the Gladstone Project)
- Central Queensland to Southern Queensland Connection
- Queensland to New South Wales Interconnector (QNI) Connect.

Table 5.5 Actionable Queensland PTI network projects, 2024 ISP

Project	ISP optimal timing (Step Change scenario)	Brief ISP Description
Gladstone Project	2030-31 Powerlink published the Gladstone Project: Candidate Priority Transmission Investment Assessment Final Assessment Report - 6 June 2025[16] targeting March 2029 for project delivery.	Increase network capacity from Central Queensland into the Gladstone area to support the area's industry once Gladstone Power Station retires[17].
Central Queensland to Southern Queensland Connection	2031-32[18]	Greatly increase the transfer limit between Central and Southern Queensland and connect to the Borumba Pumped Hydro project.

Note:

(1) Source: AEMO, 2024 Integrated System Plan, June 2024, pages 61 and 63.

16 Powerlink, Gladstone Project: Candidate Priority Transmission Investment Assessment final assessment report, June 2025.

17 On 1 October 2025, the expected closure date for the Gladstone Power Station was updated from 2035 to 31 March 2029. See AEMO, Generating Unit Expected Closure Year, October 2025.

18 Borumba PHES was modelled as an anticipated project in the 2024 ISP with a date of 2030-31.

Table 5.6 Actionable ISP network project, 2024 ISP

Project	ISP optimal timing (Step Change scenario)	Brief ISP Description
QNI Connect	2034-35	Add capacity between southern Queensland and New England, following development of the New England Renewable Energy Zone (REZ) Network Infrastructure Project. Project Assessment Draft Report (PADR) due by June 2026.

Note:

(1) Source: AEMO, 2024 Integrated System Plan, June 2024, page 63.

5.3.4 Connection point proposals

Planning of new or augmented connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements. New connections can result from joint planning with the relevant DNSP (Energex or Ergon Energy) or be initiated by generators or customers.

Table 5.7 lists connection works that are anticipated to be required within the 10-year outlook period[19].

Table 5.7 Connection point commitments (1)

Connection Point Name (2)	Proposal	Zone
Kidston Pumped Storage Hydro (3)	New PHES	Ross
Broadsound Solar Farm (3)	New Solar Farm	Central West
Lotus Creek Wind Farm	New Wind Farm	Central West
Boulder Creek Wind Farm	New Wind Farm	Central West
Woolooga Battery Energy Storage System (BESS)	New BESS	Wide Bay
Supernode BESS (3)	New BESS	Moreton
Swanbank BESS Stages 1 & 2 (3)	New BESS	Moreton
Wambo Wind Farm Stage 2 (3)	New Wind Farm	South West
Punchs Creek Solar Farm	New Solar Farm + BESS	Bulli
Wandoan Solar Farm Stage 2 (3)	Expanded Solar Farm	Surat

Notes:

(1) Powerlink has adopted AEMO's definition of 'committed' project from the System Strength Impact Assessment Guidelines Version 2.2 (effective 1 July 2024) for connection point proposals identified in the TAPR. The connection point proposals listed are as at 30 September 2025.

(2) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. conventional generator, inverter-based resource (IBR) generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(3) The listed connection point commitment is in progress (refer to Table 8.2).

Table 5.8 summarises connection point activities undertaken by Powerlink since publication of the 2024 TAPR[20]. Further details on potential new generation connections are available in the relevant TAPR template located on Powerlink's TAPR Portal as noted in Appendix F.

[19] NER, clause 5.12.1(b)(2).
[20] More broadly, key connection information in relation to the NEM can be found on AEMO's website.

Table 5.8 Connection point activities

Generator Location	Number of Applications	Number of Connection Agreements	Generator Type and Technology
North	11	0	BESS, Wind Farm, Hybrid (Solar + BESS)
Central	13	1	BESS, Wind Farm, Hybrid (Solar Farm + BESS), Gas, Load
South	15	2	BESS, Wind Farm, Hybrid (Wind Farm + BESS), Solar Farm
Total	39	3	

5.4 Proposed network developments

5.4.1 Regulated capital expenditure program

Powerlink's regulated capital expenditure program of work will continue to focus on risks arising from the condition and performance of existing aged assets, as well as emerging limitations in the capability of the network.

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are a large number of transmission assets ranging from 40 to just beyond 60 years old. A number of these assets are approaching the end of their technical service life and investment in some form is required within the 10-year outlook period to manage risks related to safety, reliability and other factors.

In conjunction with condition assessments and risk identification, as assets approach their anticipated end of technical service life, possible investment options undergo detailed planning studies to confirm alignment with future investment, optimisation and delivery strategies. These studies enable Powerlink to:

- improve and further refine options under consideration
- identify other options from those originally specified which may deliver a greater benefit to customers.

Powerlink also reviews the rating of assets throughout the transmission network periodically and has not identified any required asset deratings that would result in a system limitation as part of the 2025 annual planning review.

Information regarding possible investment alternatives, network limitations and anticipated timing is updated annually in the TAPR and includes discussion on significant changes which have occurred since publication of the previous year's TAPR.

5.4.2 Indicative costs of potential projects

Local and global demand for resources that are essential for transmission projects continues to put upward pressure on costs and extend equipment delivery timeframes. To mitigate these pressures, Powerlink has:

- developed alternative supply options for critical equipment such as 275kV circuit breakers
- implemented alternative strategies to transmission line refit works (refer to Section 5.8.1)
- continued to refine transmission augmentations to drive value for customers[21].

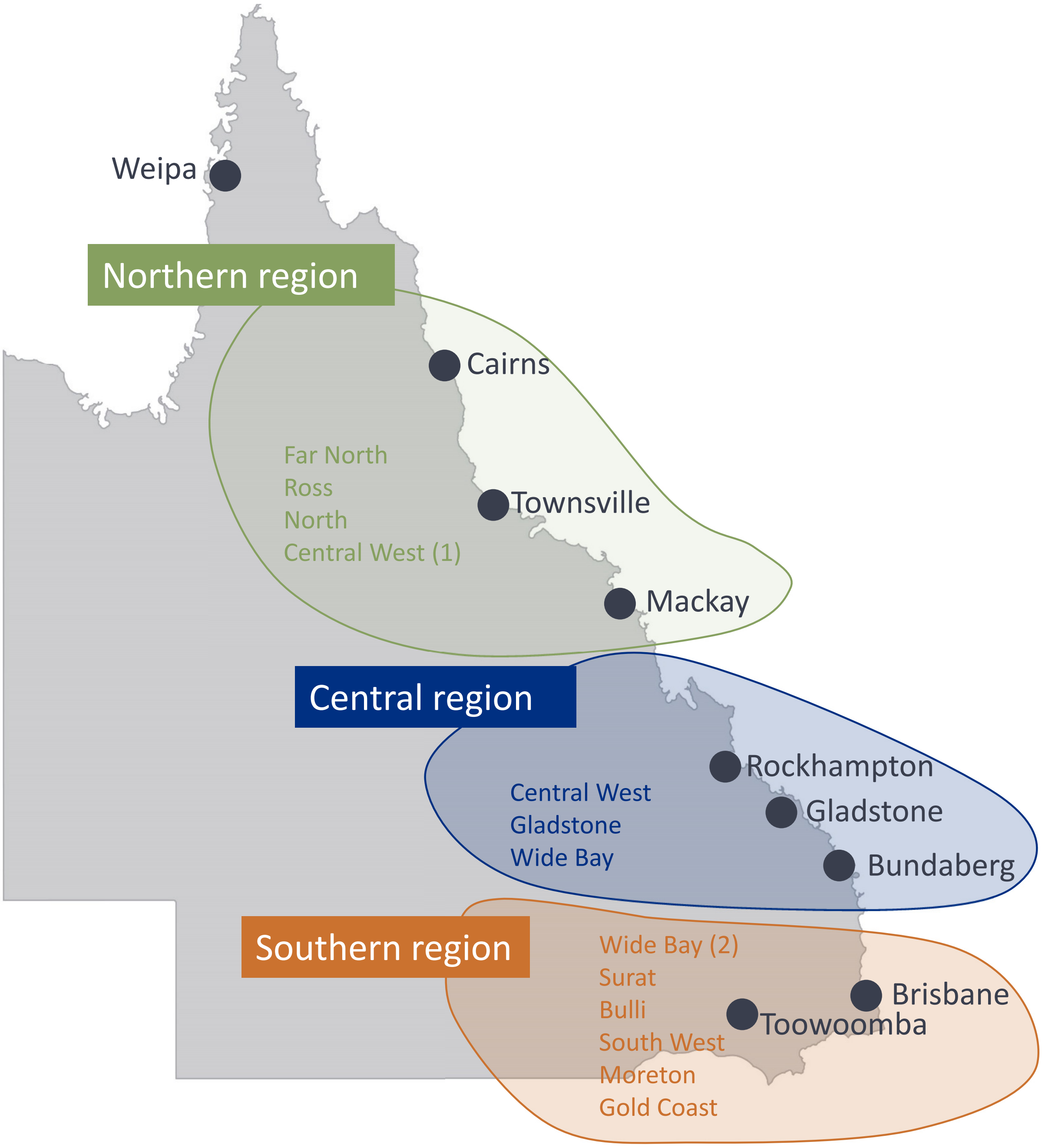
The indicative costs of potential projects identified in this chapter are updated each year to keep pace with external project cost increases, and where possible are based on other recently completed similar projects. Where there may be other factors materially influencing the updated indicative cost, such as a more granular view of condition and project scope, or a new proposed solution is identified, these factors are noted in Appendix E which summarises all proposed network investments for the 10-year outlook period. It should be noted that the indicative cost of potential projects also excludes known and unknown contingencies.

5.4.3 Geographical context

To provide geographical context, Figure 5.4 shows Queensland's energy regions and zones.

[21] For detail on external cost pressures facing TNSPs see AEMO, 2025 Electricity Network Options Report, final report, July 2025, page 32; and Powerlink, Powerlink 2027-32 Revenue Proposal (Draft), September 2025, pages 11-15.

Figure 5.4 Queensland's energy regions and zones



Notes:

(1) The Central West zone traverses the Northern and Central regions.

(2) The Wide Bay zone traverses the Central and Southern regions.

5.4.4 Investment context, timeframes and description

Powerlink has analysed investment needs and potential limitations across Powerlink's standard geographic zones (refer to sections 5.5 to 5.7).

Powerlink's planning overview (10-year outlook period of the TAPR) considers a range of options to address identified needs. When considering the replacement of existing assets, in conjunction with the broader network topology and changing external environment, Powerlink may also identify potential network reconfigurations or other options to realise synergies and efficiencies in developing the transmission network which would be economically assessed under the RIT-T (if applicable).

Information in relation to potential projects, alternatives and possible commissioning needs is revised annually based on the latest information available at the time of publication. Refer to Appendix E for the complete list of proposed network investments within the 10-year outlook period. Any significant timing and cost differences are noted in the analysis of this program of work.

Possible network investment needs likely to require RIT-T consultation within the five-year outlook period from July 2025 to June 2031 are discussed in this chapter.

Each year, taking the most recent assessment of asset condition and risk into consideration, Powerlink reviews possible commissioning dates and, where safe, technically feasible and prudent, may defer capital expenditure. As a result, there may be timing variances between the possible commissioning dates identified in the 2024 TAPR and 2025 TAPR and TAPR Templates.

5.5 North and Far North Region

The North and Far North Region covers the Far North, Ross and North zones, encompassing the northern most extent of Powerlink's transmission network. Proposed network reinvestments in this region are related to addressing risks arising from the condition of the existing network assets. Without timely intervention, these risks could lead to breaches of Powerlink's obligations under jurisdictional network, safety, environmental and NER requirements.

To maintain a safe, reliable and cost-effective supply of electricity to customers in the North and Far North Region, Powerlink is taking proactive steps to address asset condition to ensure ongoing compliance and reliability into the future. Potential solutions include like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

5.5.1 Far North zone

Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at Chalumbin, Tully South and Woree, and a coastal 132kV network from Yabulu South to Woree. This network supplies the Ergon Energy distribution network feeding the surrounding areas of Turkinje and Cairns, from Tully to Cooktown. The network also connects various renewable generators including the hydro power stations at Barron Gorge and Kareeya, Mt Emerald Wind Farm near Walkamin and Kaban Wind Farm near Tumoulin.

Figure 5.5 Far North zone transmission network

Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional capacity forecast to be required due to load driven network limitations in the Far North zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold will be required to address the risks arising from the condition of assets in the Far North zone within the next five years.

Joint RIT-T consultation – Maintaining Reliability of Supply to Kamerunga and Cairns Northern Beaches Area

The Woree to Kamerunga 132kV double circuit transmission line provides critical supply to the Cairns northern beaches region, as well as connecting the Barron Gorge Hydro Power Station to the transmission network. A significant proportion of the transmission line traverses built-up residential areas, including a significant number of encroachments on the existing feeder easement. There are a number of major and minor road crossings causing access and construction work challenges.

Kamerunga Substation is located in western Cairns and provides bulk electricity supply to Ergon Energy's distribution network in the northern Cairns region which includes Kamerunga, Smithfield and the northern beaches areas, and also provides connection to the Barron Gorge Power Station. The area surrounding the substation is residential and located along the flood plain of the Barron River.

In December 2024, Powerlink issued a joint Project Specification Consultation Report (PSCR) with Ergon Energy to address network needs in the Kamerunga, Cairns and northern beaches area. The PSCR identified two credible options to address the identified need, with the primary difference between options being an additional underground section of the transmission line rebuild. Powerlink did not receive any submissions in response to the PSCR, and is progressing the PADR with Ergon Energy.

Joint RIT-T consultation with Ergon Energy	
Asset details	Transmission line constructed in 1963. Life extension in 2014 on certain components nearing end of technical service life. Kamerunga Substation established in 1976.
Project driver	Transmission line: emerging condition risks due to structural corrosion. Substation: emerging condition, obsolescence and compliance risks on 132kV primary plant and secondary systems and risks related to a potential future flood event.
Project timing	December 2028.
Proposed network solution	Rebuild the existing double circuit transmission line with a new double circuit transmission line (overhead/underground alignment) from Woree to Kamerunga substations and associated Ergon Energy works. Replacement of primary plant including additional switching functionality and secondary systems upfront with Air Insulated Switchgear (AIS) technology on an adjacent substation site at Kamerunga and associated Ergon Energy works. Construction of a new building to contain 22kV primary and secondary systems by December 2028 at an estimated cost of $201 million.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 22kV network of up to a peak 85MW, and up to a peak 1,200MWh per day on a continuous basis. This transmission line also facilitates the Barron Gorge Hydro Power Station connection in the area.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Transmission Lines

Ross to Chalumbin to Woree 275kV transmission lines

Although renewable generation in Far North Queensland is increasingly supplying load in the Cairns region (refer to Figure 6.11), the 275kV and 132kV transmission system plays a critical role in maintaining reliability of supply by connecting generation in Central and North Queensland to this region.

Remote supply to the Cairns region is delivered through the inland 275kV network to Ross, near Townsville. From Ross it is transferred via a 275kV transmission line to Chalumbin, continuing via a second 275kV transmission line from Chalumbin to the Woree Substation on the outskirts of Cairns. These 275kV transmission lines also provide connections to the Mt Emerald and Kaban Wind Farms and the Kareeya Hydro Power Station. A 275kV connection into Woree Substation was energised in June 2024. Remaining substation works at Tully and Yabulu South substations were completed at the end of September 2024. Minor associated works across Far North Queensland are expected to be completed by the end of 2025.

The double circuit 275kV transmission line between Ross and Chalumbin (via Guybal Munjan Substation) substations is 244km in length and comprises 528 steel lattice towers. The line traverses the Northern Queensland tropical rainforest, passing through environmentally sensitive, protected areas and crossing numerous regional roads and rivers. The delivery of the required renewal works will be complex and need to be completed outside of summer peak load and the wet season.

Potential consultation	Maintaining Reliability of Supply in the Cairns Region Stage 2: Addressing the Condition Risks of the Transmission Towers between Ross and Chalumbin
Asset details	Constructed in 1989.
Project driver	Emerging condition risks due to structural corrosion.
Project timing	June 2031.
Proposed network solution	Refit the double circuit transmission line between Ross (via Guybal Munjan Substation) and Chalumbin substations, at an estimated cost of $39 million by June 2031.
Possible non-network solutions	The Ross to Chalumbin transmission lines provide injection to the north area of close to 400MW at peak and up to 6,000MWh per day. The network configuration also facilitates generator connections in the area and enables the provision of system strength and voltage support for the region.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Substations

Chalumbin 275/132kV Substation

Chalumbin Substation is a major substation in the 275kV power transfer corridor between the Ross and Far North zones and provides supply to the local 132kV network in the Cairns and Atherton tablelands regions.

Anticipated consultation	Maintaining Reliability of Supply at Chalumbin
Asset details	Established in 1988.
Project driver	Condition driven replacement to address risks on 275kV and 132kV primary plant and secondary systems.
Project timing	June 2031.
Proposed network solution	Substation reinvestment comprising of selected replacement of primary plant and secondary systems at an estimated cost of $58 million by June 2031.
Possible non-network solutions	Powerlink is not aware of any non-network proposals that can address this requirement in its entirety. Potential non-network solutions would need to provide supply to the 132kV network of up to a peak 100MW, and up to a peak 965MWh per day on a continuous basis. For the 275kV Chalumbin works, a non-network solution would need to provide injection to the north area of close to 400MW at peak and up to 6,000MWh per day.
Other possible network solutions	Staged selected replacement of the 275kV and 132kV primary plant and secondary systems by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Tully 132/22kV Substation

Tully Substation is located around 120km south of Cairns between Ross and Cairns and provides supply to the local 132kV network in the Cairns and Atherton tablelands regions.

Potential consultation	Maintaining Power Transfer Capability and Reliability of Supply at Tully
Asset details	Established in 1977.
Project driver	Condition driven replacement to address risks on one of the 132/22kV transformer.
Project timing	June 2028.
Proposed network solution	Replacement of Transformer 2 at an estimated cost of $9 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide up to 15MW at peak and up to 200MWh per day on a continuous basis to provide supply to the 22kV network at Tully.
Other possible network solutions	Life extension of Transformer 2 by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[22]

Condition assessment has identified emerging condition risks arising from the condition of the 132kV transmission line between Chalumbin and Turkinje around 2035. At this time, an option would be to establish a 275kV substation and cut into an existing 275kV circuit between Chalumbin and Woree substations to supply Turkinje. Should this option proceed, there will be an opportunity to retire the existing 132kV transmission line from Chalumbin to this new substation.

5.5.2 Ross zone

Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville and Far North Queensland. Parts of the 132kV network are located closer to the coast in a high salt-laden wind environment, leading to accelerated structural corrosion. Townsville is supplied by a 132kV transmission network to the south and west of the greater load area providing supply to Ergon Energy's 66kV distribution network. Connection points are located at the Townsville South 132/66kV, Townsville East 132/66kV, Dan Gleeson 132/66kV, Garbutt 132/66kV, and Alan Sherriff 132/11kV substations.

Figure 5.6 Northern Ross zone transmission network

22 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 5.7 Southern Ross zone transmission network

Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional capacity forecast to be required due to load driven network limitations in the Ross zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the Ross zone within the next five years.

Transmission Lines

Ross to Dan Gleeson 132kV transmission lines

Electricity supply to the Townsville Central Business District (CBD) is provided from Ross Substation by 132kV transmission lines to Dan Gleeson, Alan Sherriff and Garbutt substations.

Potential consultation	Maintaining Reliability of Supply between Ross and Dan Gleeson
Asset details	Constructed in 1963 and operates in an aggressive tropical coastal environment.
Project driver	Emerging condition risks due to structural corrosion.
Project timing	June 2031.
Proposed network solution	Refit of the transmission line between Ross and Dan Gleeson substations, at an estimated cost of $12 million by June 2031.
Possible non-network solutions	The Ross to Dan Gleeson transmission lines provide part of the injection to the Townsville central business area. Potential non-network solutions would need to provide equivalent support of close to 136MW at peak and up to 1,600MWh per day.
Other possible network solutions	Rebuild the 132kV transmission line between Ross and Dan Gleeson substations by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Substations

Ingham South 132kV Substation

Ingham South Substation is a major injection point into Ergon Energy's 66kV distribution network, providing supply to Ingham and the surrounding area.

Current consultation	Maintaining Reliability of Supply and Addressing Condition Risks at Ingham South
Asset details	Established in 2005.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV primary plant and secondary systems.
Project timing	December 2028.
Proposed network solution	In June 2025, Powerlink published a PSCR to maintain reliability of supply and address condition risks at Ingham South. The PSCR identified the following preferred option: • replacing the hybrid switchgear modules in-situ with air insulated switchgear and replacing secondary systems in a new control building on existing substation platform as the preferred option. The estimated cost is $26 million with a targeted completion date of December 2028. Powerlink did not receive any submissions on the PSCR and is progressing to the Project Assessment Conclusions Report (PACR) stage of the RIT-T.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 66kV network at Ingham South of up to 22MW and up to 370MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.
Other possible network solutions	The PSCR described another credible option: • Extend substation platform and replace hybrid switchgear modules with air insulated switchgear using adjacent spare bay locations. Replace secondary systems in a new control building by 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Alan Sherriff 132kV Substation

Alan Sherriff Substation is a major injection point into Ergon Energy's 11kV distribution network providing supply to the Townsville area.

Potential consultation	Addressing the Secondary Systems Condition Risks at Alan Sherriff
Asset details	Established in 2002.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on the 132kV secondary systems.
Project timing	June 2028.
Proposed network solution	Selected secondary systems replacement an estimated cost of $26 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 66kV and 11kV network at Alan Sherriff of up to 77MW and up to 480MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.
Other possible network solutions	In-situ selected replacement of secondary systems by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Townsville South 132kV Substation

Townsville South is a major substation supplying the city of Townsville, the major industrial load of Sun Metals Zinc Refinery and serving as a connection point for the Mt Stuart Power Station.

Potential consultation	Addressing the Secondary Systems Condition Risks at Townsville South
Asset details	Established in 1977.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2028.
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $11million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide supply to Townsville East and Townsville South (including Sun Metals) of up to 150MW at peak and up to 3,000MWh per day. It would also need to facilitate the connection of Mt Stuart Power Station.
Other possible network solutions	Full secondary systems replacement by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Townsville East 132kV Substation

Townsville East is a major substation supplying the Townsville CBD and port.

Potential consultation	Addressing the Secondary Systems Condition Risks at Townsville East
Asset details	Established in 2008.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2028.
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $10 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide supply to Townsville East of up to 40MW at peak and up to 130MWh per day.
Other possible network solutions	Full secondary systems replacement by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Garbutt 132kV Substation

Garbutt Substation is a major injection point into Ergon Energy's 66kV distribution network providing supply to the Townsville area.

Potential consultation	Addressing the Secondary Systems Condition Risks at Garbutt
Asset details	Established in late 1950s; last replacement in 2004.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2029.
Proposed network solution	Full replacement of secondary systems at an estimated cost of $13 million by June 2029.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 66kV network at Garbutt Substation of up to 120MW and up to 1,350MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.
Other possible network solutions	In-situ replacement of secondary systems by June 2029.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[23]

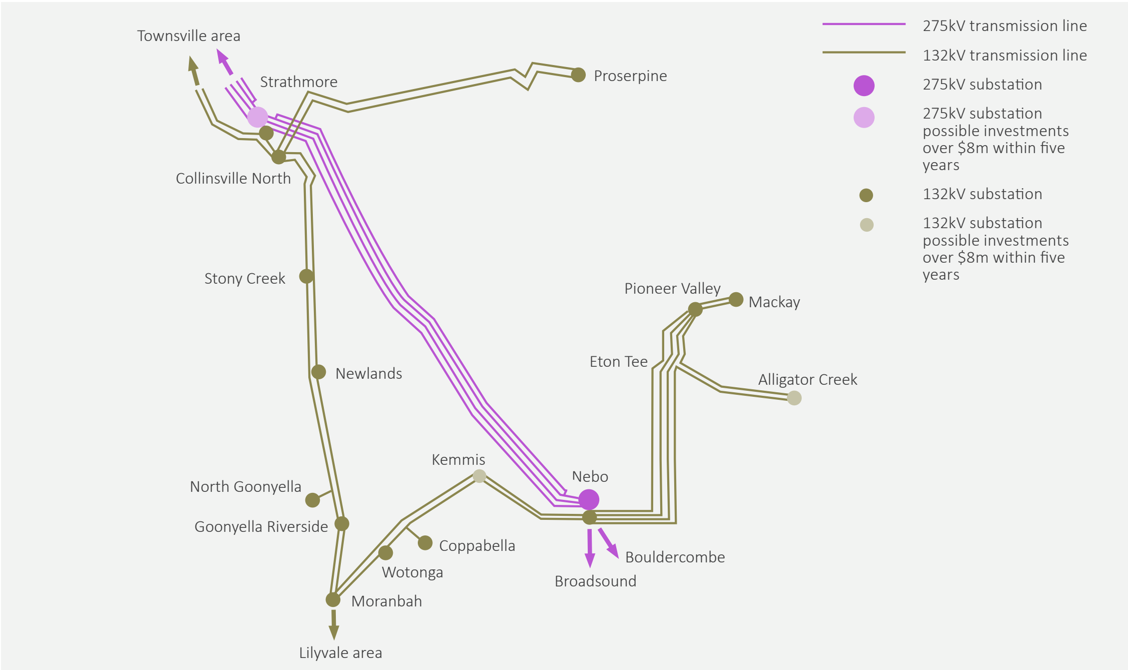
Powerlink has not identified any potential asset retirements in the Ross zone within the 10-year outlook period.

5.5.3 North zone

Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form part of the 275kV transmission network supplying the North zone. Double circuit inland and coastal 132kV transmission lines supply regional centres and infrastructure related to mines, coal haulage and ports arising from the Bowen Basin mines. The coastal network in this zone is characterised by transmission line infrastructure in a corrosive environment which make it susceptible to premature ageing.

Figure 5.8 North zone transmission network



Possible load driven limitations

Based on Powerlink's Central scenario forecast, additional capacity is required due to load driven network limitations in the North zone within the next five years to meet reliability obligations. New and expanded mine operations in the Northern Bowen Basin are forecast to exceed Powerlink's reliability obligations at the end of the 10-year forecast period.

There has also been significant interest from customers in the Northern Bowen Basin in electrifying mining operations. This emerging demand may require future load-driven investment within Powerlink's network. Further information is provided in Section 7.2.2.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the North zone within the next five years.

Transmission Lines

Powerlink has not identified any potential network investments to address the risks arising from the condition of transmission lines in the North zone within the next five years.

Substations

Strathmore 275/132kV Substation

Strathmore Substation is a major injection point to supply Ergon Energy's distribution network and Powerlink's direct connected customers in the Northern Bowen Basin.

[23] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Anticipated consultation	Addressing the SVC Secondary Systems Condition Risks at Strathmore
Asset details	Established in 2007.
Project driver	SVC secondary systems condition risks at Strathmore Substation.
Project timing	December 2029.
Proposed network solution	Replacement of the Strathmore SVC secondary systems at an estimated cost of $24 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide dynamic voltage support of up to 260MVAr capacitive and 80MVArs inductive.
Other possible network solutions	Staged replacement of the Strathmore SVC secondary systems by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Alligator Creek 132kV Substation

Alligator Creek Substation is a bulk supply point from mines in the Bowen Basin to the coal loading terminals of Hay Point and Dalrymple Bay and provides supply to Ergon Energy distribution network for the surrounding communities to the south of Mackay.

Potential consultation	Addressing Primary Plant and Secondary Systems Condition Risks at Alligator Creek
Asset details	Established in 1982.
Project driver	132kV primary plant and secondary systems condition risks at Alligator Creek Substation.
Project timing	December 2030.
Proposed network solution	Selected 132kV primary plant, and 132kV and SVC secondary systems at an estimated cost of $34 million by December 2030.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 132kV loads connected at Alligator Creek Substation of up to 70MW and up to 1,500MWh per day.
Other possible network solutions	Staged selected replacement of 132kV primary plant, and 132kV and SVC secondary systems by December 2030.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[24]

Powerlink has not identified any potential asset retirements in the Ross zone within the 10-year outlook period.

5.6 Central Region

The Central Region covers the Central West and Gladstone zones. This region:

- hosts some of Powerlink's largest industrial customers together with significant coal fired generation
- offers considerable opportunities for the development of new industries
- is pivotal to the supply of power to Northern and Southern Queensland
- plays a major role in supporting industry, rail systems and mines.

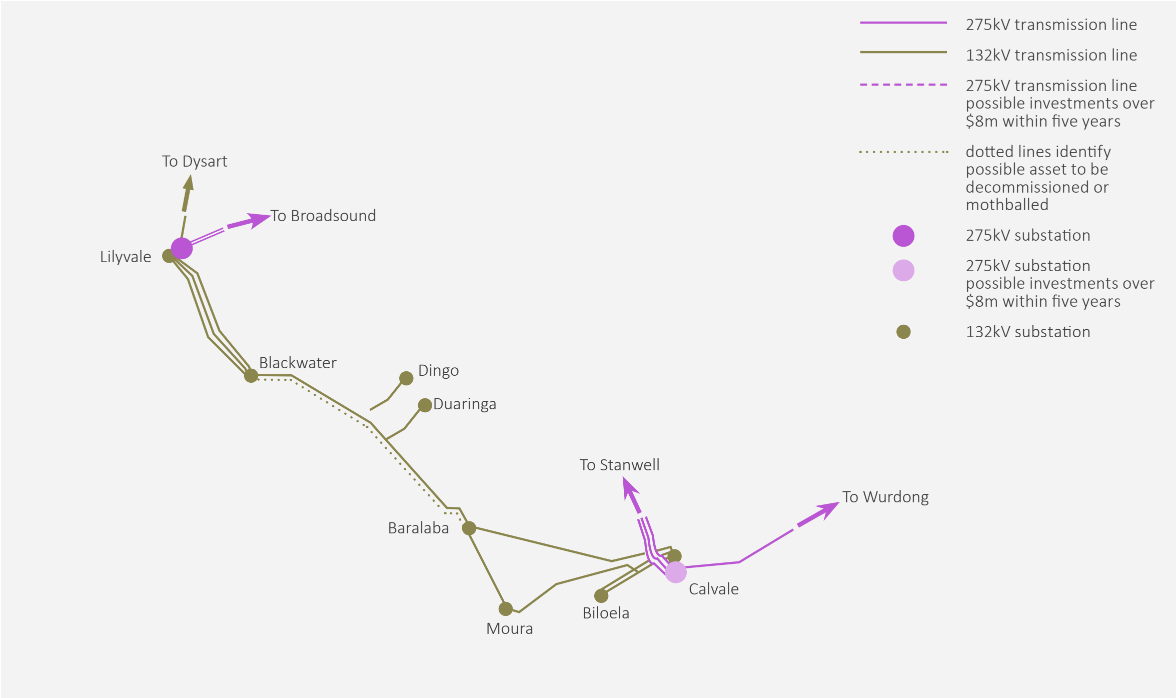
5.6.1 Central West zone

Existing network

The Central West 132kV network was developed between the mid-1960s and late 1970s to meet the requirements of mining activity in the southern Bowen Basin. The 132kV injection points for the network are taken from Calvale and Lilyvale 275kV substations (refer to Figure 5.9). The network is located more than 150km from the coast in a dry environment, making infrastructure less susceptible to corrosion. As a result, transmission lines and substations in this region have met (and in many instances exceeded) their anticipated service life and will require replacement or rebuilding in the near future.

24 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 5.9 Central West 132kV transmission network



Possible load driven limitations

Based on Powerlink's Central scenario forecast there is no additional capacity forecast to be required in the Central West zone within the next five years to meet load driven reliability obligations. Powerlink is engaging with potential large load customers in the area to firm up new load requirements.

Possible network investments within five years

Proposed network investments (which include reinvestments and augmentations) in this zone are related to addressing risks arising from the condition of the existing network assets. Without timely intervention, these risks could lead to breaches of Powerlink's obligations under jurisdictional network, safety, environmental and NER requirements.

To maintain a safe, reliable and cost-effective supply of electricity to meet the load requirements of customers in the Central West zone into the future, Powerlink is taking proactive steps to address asset condition to ensure ongoing compliance and reliability into the future. Potential solutions include like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission Lines

Powerlink has not identified any potential network investments to address the risks arising from the condition of transmission lines in the Central West zone within the next five years.

Substations

Calvale 275/132kV Substation

Calvale Substation is a critical part of the Central West Queensland transmission network and provides connection to Callide B and Callide C generators and potential new generators in the zone. Calvale Substation is also a major transmission node in Central Queensland connecting power flows between northern, central and southern Queensland.

Potential consultation	Maintaining Reliability of Supply at Calvale
Asset details	Established in the mid-1980s.
Project driver	Addressing the 275kV primary plant condition risks.
Project timing	June 2031.
Proposed network solution	Selected primary plant replacement at Calvale Substation at an estimated cost of $39 million by June 2031.
Possible non-network solutions	Potential non-network solutions would need to address two separate areas: • supply to Moura and Biloela loads of approximately 100MW and 2,000MWh per day • supply to Boyne Island Smelter loads of up to 425MW and 9,960MWh per day.
Other possible network solutions	Full primary plant replacement by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Broadsound 275kV Substation

Broadsound substation was established in 1984 and is primarily a major transmission node connecting power flows between Northern and Central Queensland. It is also the hub to Lilyvale Substation and Central West loads.

Potential consultation	Maintaining Reliability of Supply at Broadsound
Asset details	Established in 1983. Further extensions have been made with additions of 275kV feeders to the west, south and north.
Project driver	Addressing the 275kV primary plant condition risks.
Project timing	June 2030.
Proposed network solution	Selected primary plant replacement at Broadsound Substation at an estimated cost of $19 million by June 2030.
Possible non-network solutions	Potential non-network solutions would need, as a minimum, to provide supply to Lilyvale and Blackwater loads of approximately 220MW and 4,050MWh per day.
Other possible network solutions	Full primary plant replacement by June 2030.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[25]

Calvale to Moura to Baralaba 132kV transmission lines

Subject to the outcome of further analysis and RIT-T consultation, a new 132kV double circuit transmission line may be constructed between Calvale and Moura substations due to a step change in load growth at Moura Substation or end of technical service life of the existing transmission lines within the 10-year outlook period. The reconfiguration would allow Powerlink to mothball the existing single circuit transmission lines between Calvale and Baralaba, and Baralaba and Moura substations, and the Baralaba Substation, at the end of their technical service lives and be retired from service.

Baralaba to Blackwater 132kV transmission line

This 132kV inland transmission line was constructed in the mid-1960s to support loads in the Central West area. Due to network reconfigurations this line has no enduring need, and has been mothballed as part of an economic end of technical service life strategy. The line is energised from Blackwater Substation (and disconnected at the Baralaba Substation end) for maintenance purposes.

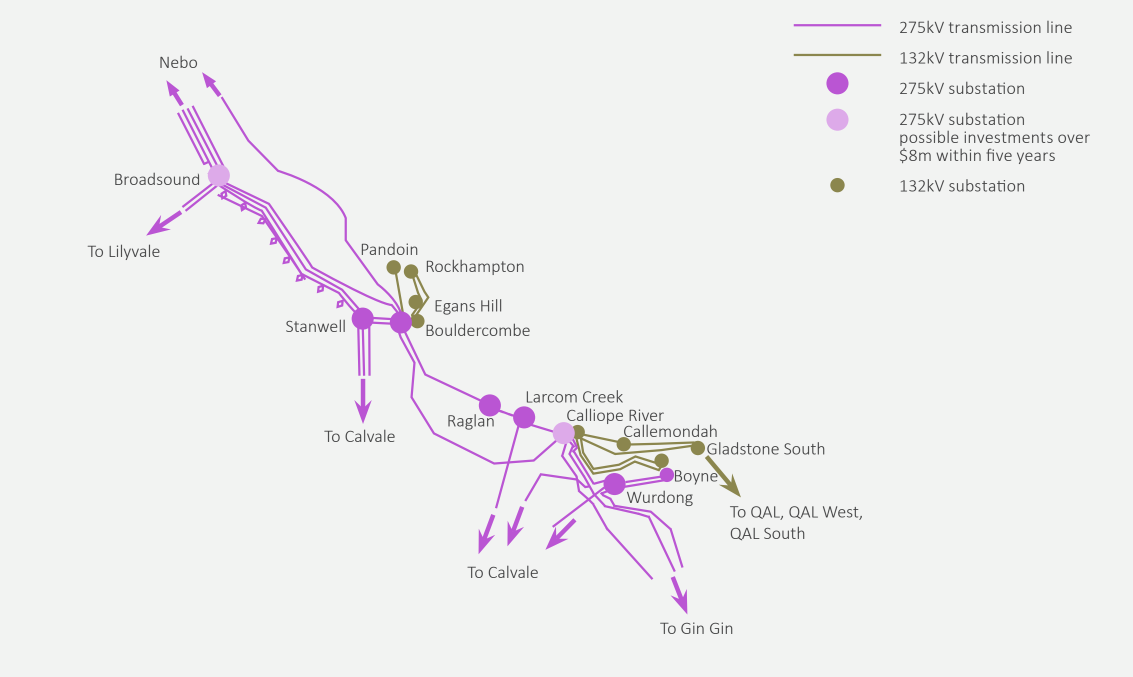
5.6.2 Gladstone zone

Existing network

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station and has evolved over time with the addition of the Wurdong Substation and 275kV supply into Boyne Smelters Limited in the early 1990s.

[25] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 5.10 Gladstone transmission network



Possible load driven limitations

The network in Gladstone supports a range of industrial customers including:

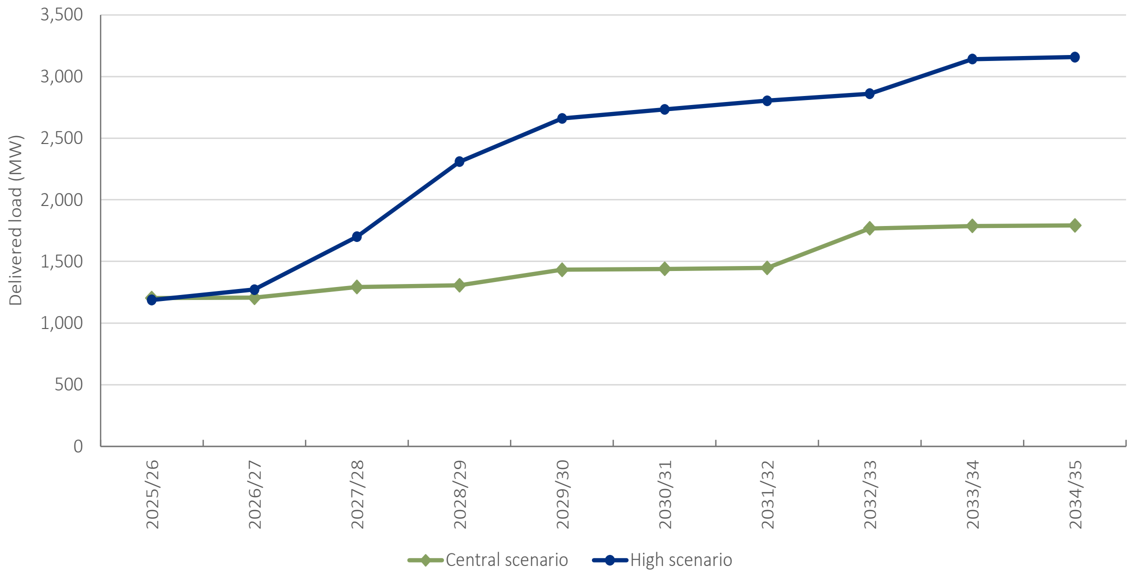
- two alumina refineries
- an aluminium smelter
- chemical manufacturing
- Queensland's largest multi-commodity port
- a range of other economically significant industries.

Many of these large customers are expected to electrify their production processes over the coming years, which will place additional demand on the energy grid, particularly following the potential retirement of the Gladstone Power Station in March 2029[26]. Electrification of industry, and the potential retirement of Gladstone Power Station, will have a significant impact on the transmission capacity required to maintain reliability of supply in the Gladstone zone and power system security.

Powerlink's 2025 demand forecast shows that electrical load in the Gladstone area is expected to increase over the same time period as the potential closure of Gladstone Power Station, increasing the need for new supply to meet demand in the area. Furthermore, there continues to be significant interest from multiple proponents of large direct connect loads, the aggregate of which is depicted by the high scenario trace in Figure 5.11. These loads are not at a stage to be considered in the Central demand forecast scenario (refer to Table 2.1).

[26] AEMO, Generating Unit Expected Closure Year, October 2025.

Figure 5.11 Gladstone zone 10% Probability of Exceedance Forecast (1)



Note:

(1) This equates to a Probability of Exceedance (PoE) where conditions are exceeded once in 10 years.

Refer to Appendix E for possible network reinvestments in the Gladstone zone.

Gladstone Project

Upgrades to the network are required to enable new supply and deliver the necessary power to the Gladstone area. Further future investments will be required beyond the Gladstone Project should one or more large loads reach a sufficiently advanced stage to be incorporated in the central demand forecast scenario.

As part of the PTI framework, Powerlink completed an assessment of the Gladstone Project in June 2025, with the preferred option involving:

- constructing a new 275kV high-capacity double circuit transmission line between Calvale and Calliope River substations, switched through a new substation located at Gladstone West
- establishing a third 275/132kV transformer at Calliope River Substation
- constructing a new 275kV high-capacity double circuit transmission line between Bouldercombe and Larcom Creek substations switched through a new Gladstone West Substation
- investment in assets to compensate for the loss of system security services in the Gladstone area when Gladstone Power Station closes, including a mixture of network and non-network components.

The indicative capital cost of the preferred option $1,788 million (real 2025 dollars)[27]. Powerlink continues to work closely with the Queensland Government on the next phase of the project, noting the Queensland Government Energy Roadmap recognises the project as a critical transmission project for the 2025 to 2030 period[28].

Possible asset retirements[29]

Callide A to Gladstone South 132kV transmission double circuit line

The 132kV transmission line was constructed in the mid-1960s to support the loads in the Gladstone area. Due to reconfiguration in the area, this transmission line is currently disconnected and is not in service. The transmission line will be retired from service within the 10-year outlook period.

5.7 Southern Region

The Southern Region covers the Wide Bay, Surat, Bulli, South West, Moreton and Gold Coast zones. The region includes a diverse range of industries and large load centres with considerable opportunity to connect generation to the transmission network. It also includes the Queensland section of QNI.

27 Powerlink, Gladstone Project: Candidate Priority Transmission Investment, final assessment report, June 2025, page 5.
28 Queensland Government, Energy Roadmap, October 2025, page 39.
29 Operational works, such as asset retirements, do not form part of Powerlink’s capital expenditure budget.

Proposed network reinvestments in this region are related to addressing risks arising from the condition of the existing network assets. Without timely intervention, these risks could lead to breaches of Powerlink's jurisdictional network, safety, environmental and NER requirements.

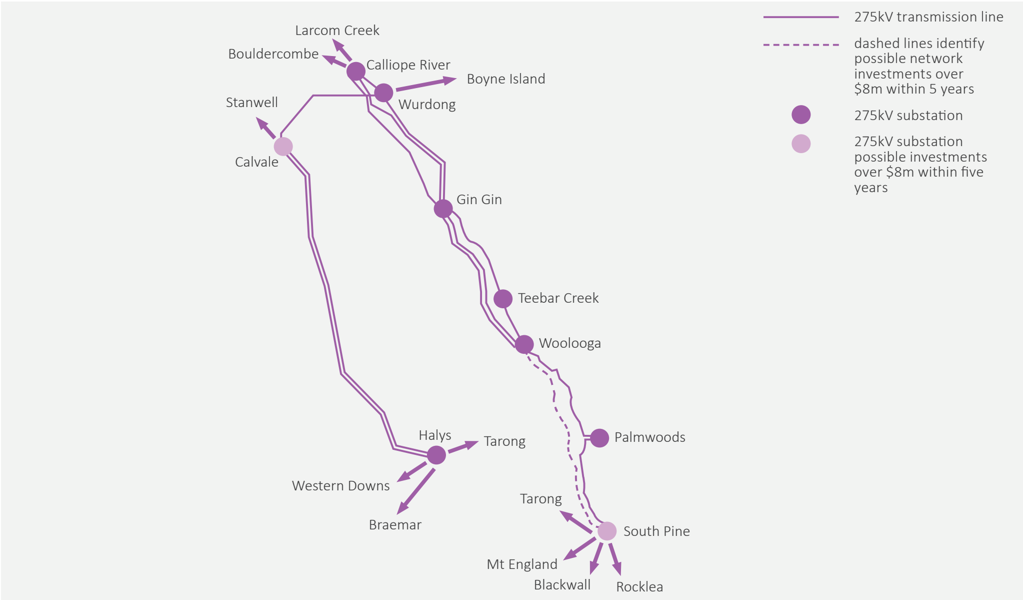
To maintain a safe, reliable and cost-effective supply of electricity to customers in the Southern Region, Powerlink is taking proactive steps to address asset condition to ensure ongoing compliance and reliability into the future. Potential solutions include like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

5.7.1 Wide Bay zone

Existing network

The Wide Bay zone supplies loads in the Bundaberg and Maryborough region, and forms part of Powerlink's eastern Central Queensland to South Queensland (CQ-SQ) transmission corridor. This corridor was constructed in the 1970s and 1980s and consists of single circuit 275kV transmission lines between Calliope River and South Pine substations. These transmission lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 5.12 CQ-SQ transmission network



Transmission network overview

In its current form, the CQ-SQ transmission network offers a great deal of flexibility for possible generation dispatches. However, it occasionally imposes constraints to market operation. In order for power to move from Northern and Central Queensland, to Southern Queensland and the southern states, it must be transferred through the CQ-SQ grid section. The utilisation may increase following the final releases of capacity associated with the commissioning of the QNI Minor project (refer to Section 6.6.10).

Possible network investments within five years

Powerlink anticipates potential network reinvestments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the Wide Bay zone within the next five years.

Transmission Lines

CQ-SQ transmission line

The coastal CQ-SQ transmission network between the Calliope River and South Pine substations provides essential supply sharing between the generation in Central and North Queensland and the loads in Central and Southern Queensland.

This corridor supplies major injection points at Gin Gin, Teebar Creek, Woolooga and Palmwoods 275/132kV substations for the Wide Bay and Sunshine Coast areas. The Ergon Energy 132kV and Energex 132/110kV subtransmission systems supply bulk supply points along these areas. The corridor also provides connection to large-scale VRE and storage projects.

The coastal CQ-SQ transmission network assets are expected to reach the end of their technical service life within the next 20 years. A key consideration is that this corridor is comprised solely of single circuit 275kV towers that may make cost-effective refit strategies less viable compared to double circuit tower rebuilds in targeted sections.

With varying distance from the ocean, and localised industrial pollution, the Calliope River to South Pine 275kV single circuit transmission lines are subject to different environmental and atmospheric conditions and have, over time, experienced structural degradation at different rates.

Emerging condition and compliance risks have been identified that structural repairs due to above ground corrosion may be required on the following assets:

- Within the next five years:
  - One 275kV single circuit transmission line from Woolooga to South Pine substations built in 1972.
- Within the next six to 10 years:
  - Three 275kV single circuit transmission lines from Calliope River to Gin Gin Substation built in 1972, 1976 and 1981
  - One 275kV single circuit transmission line from Gin Gin to Woolooga built in 1972
  - One 275kV single circuit transmission line from Palmwoods to South Pine built in 1976.

Strategies to address the transmission line sections with advanced corrosion in the five-year outlook will be economically assessed in consideration of longer-term network needs. This will also consider increasing line ratings by increasing ground clearances where it is economic to do so.

Powerlink is progressing a holistic planning approach for the coastal 275kV CQ-SQ corridor which recognises the corridor's strategic importance within the Queensland backbone transmission network. An assessment of condition related expenditure against the economic benefits of transmission line rebuild are central to this strategy.

One potential strategy is the progressive rebuild of two of the 275kV single circuit transmission lines from Calliope River to South Pine as high-capacity double circuit lines utilising high temperature conductor, if and when it is economic to do so.

Further information on strategic transmission network developments along this corridor are provided within Section 7.4.

Possible asset retirements[30]

Powerlink has not identified any potential asset retirements in the Wide Bay zone within the next 10 years.

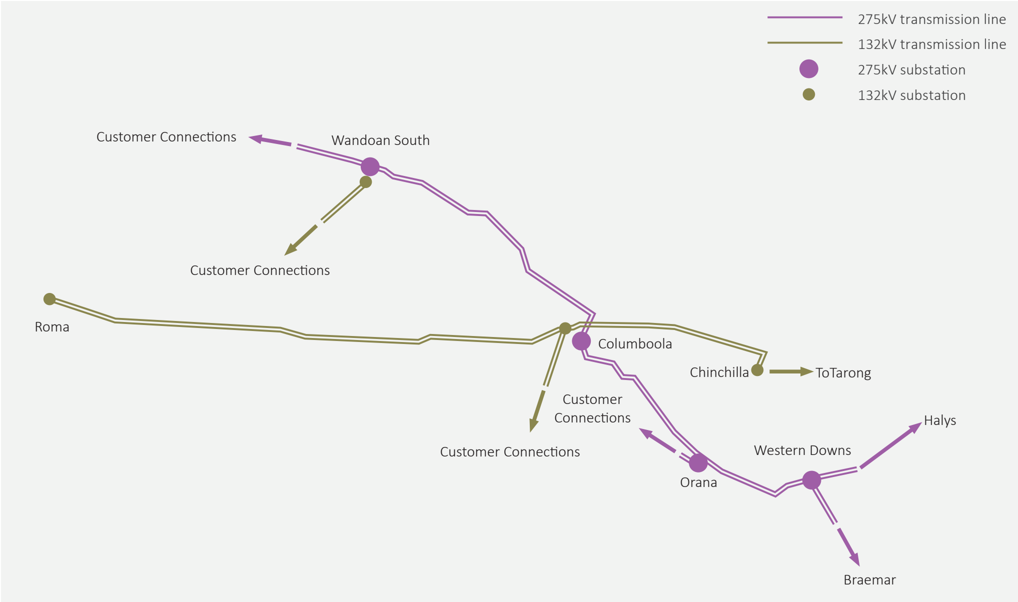
5.7.2 Surat zone

Existing network

The Surat zone is defined as the area north-west of Western Downs Substation. The area has significant development potential given the vast reserves of gas and (more recently) renewable energy. Utilisation of assets in the area is forecast to continue due to new developments of VRE projects, coal seam gas upstream processing facilities by multiple proponents, together with the supporting infrastructure and services.

30 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 5.13 Surat Basin North West area transmission network



Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional load driven capacity forecast to be required as a result of network limitations in the Surat zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink does not anticipate any potential network investments above the RIT-T cost threshold are required to address the risks arising from the condition of assets in the Surat zone within the next five years.

Possible asset retirements[31]

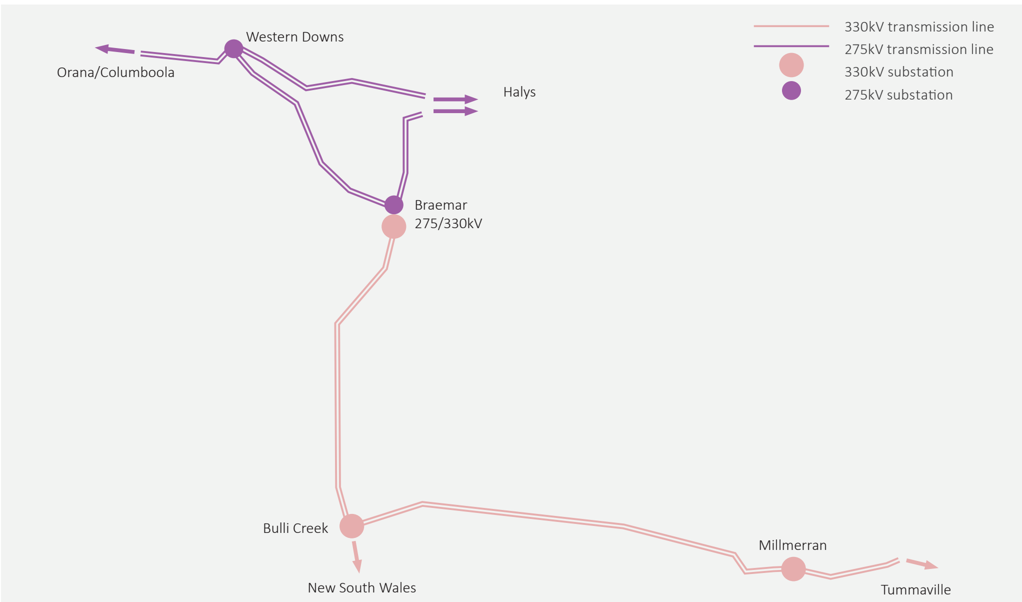
Powerlink has not identified any potential asset retirements in the Surat zone within the next 10 years.

5.7.3 Bulli zone

Existing network

The Bulli zone is defined as the area surrounding Goondiwindi and the 330kV and 275kV network south of Kogan Creek Power Station and west of Millmerran Power Station.

Figure 5.14 Bulli area transmission network



31 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional load driven capacity forecast to be required as a result of network limitations in the Bulli zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink does not anticipate any potential network investments above the RIT-T cost threshold are required to address the risks arising from the condition of assets in the Bulli zone within the next five years.

Possible asset retirements[32]

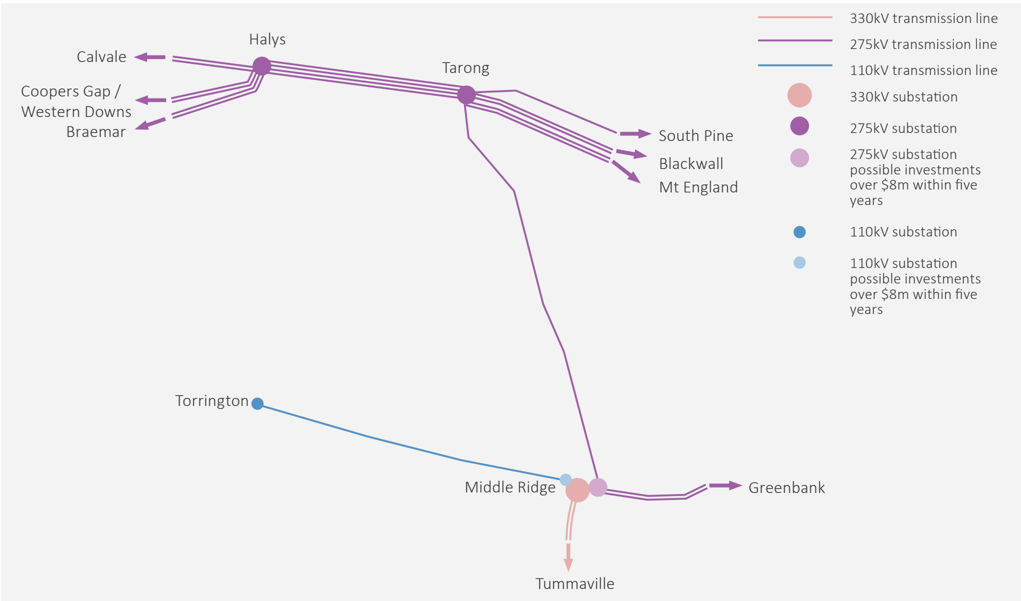
Powerlink has not identified any potential asset retirements in the Bulli zone within the 10-year outlook period.

5.7.4 South West zone

Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge.

Figure 5.15 South West area 300kV and 275kV transmission network



Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional load driven capacity forecast to be required as a result of network limitations in the South West zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the South West zone within the next five years.

Transmission Lines

Powerlink has not identified any potential network investments to address the risks arising from the condition of transmission lines in the South West zone within the next five years.

Substations

Middle Ridge 330/275/110kV Substation

Middle Ridge Substation, located south of Toowoomba, is a major transmission node between South West and South East Queensland, as well as an essential bulk supply point for local and South East Queensland loads, including Toowoomba and the Darling Downs area. The majority of secondary systems were commissioned between 2002 and 2007.

[32] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Anticipated consultation	Addressing the Secondary Systems Condition Risks at Middle Ridge
Asset details	Established in 1965.
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 275/110kV secondary systems.
Project timing	June 2031.
Proposed network solution	Replacement of all 275/110kV secondary systems at an estimated cost of $63 million by June 2031.
Possible non-network solutions	Potential non-network solutions would need to provide supply to the 110kV network of up to 120MW and 2,300MWh per day.
Other possible network solutions	Selective replacement of 275/110kV secondary systems equipment by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[33]

Powerlink has not identified any potential asset retirements in the South West zone within the 10-year outlook period.

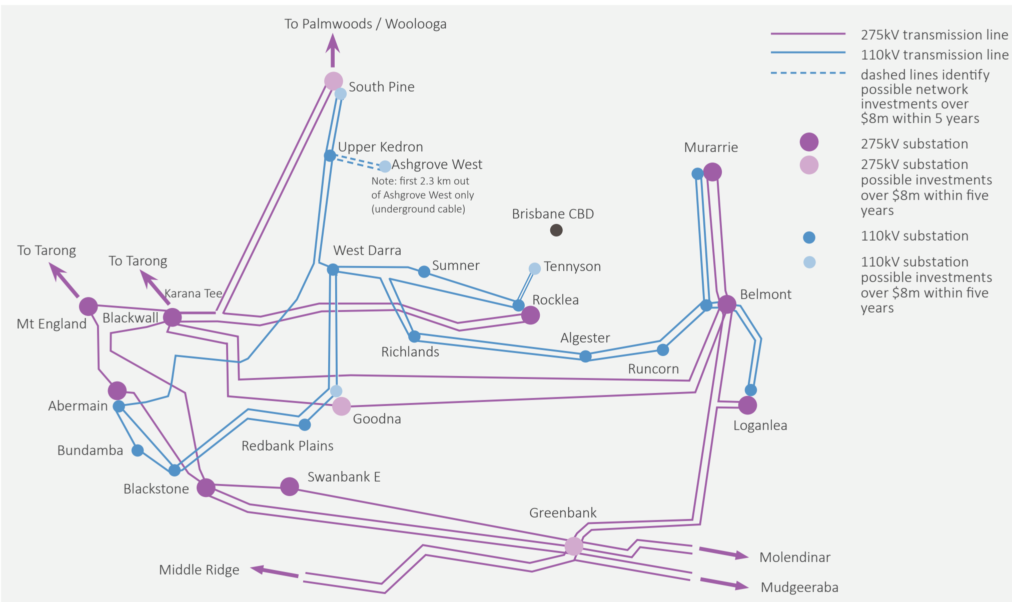
5.7.5 Moreton zone

Existing network

The Moreton zone includes a mix of 275kV and 110kV transmission networks servicing a number of significant load centres in south-east Queensland, including the Sunshine Coast, greater Brisbane, Ipswich and northern Gold Coast regions.

Future investment needs in the Moreton zone are substantially arising from the condition and performance of 275kV and 110kV assets in the greater Brisbane area. The 110kV network in the greater Brisbane area was progressively developed from the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth from the early 1970s. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane Central Business District (CBD).

Figure 5.16 Greater Brisbane transmission network



Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional load driven capacity forecast to be required in the Moreton zone within the next five years to meet reliability obligations.

[33] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the Moreton zone within the next five years.

Transmission Lines

The 110kV and 275kV transmission lines in the greater Brisbane area are located between 20km and 40km from the coast, traversing a mix of industrial, high density urban and semi-urban areas. The majority of assets are reasonably protected from the prevailing coastal winds and are exposed to moderate levels of pollution related to the urban environment. These assets have, over time, experienced structural corrosion at similar rates, with end of technical service life for most transmission line assets (refer to Table 5.9) expected to occur towards the end of the 2020s and into the early 2030s.

Underground 110kV cable between Upper Kedron and Ashgrove West

The 110kV transmission line between Upper Kedron and Ashgrove West substations is one of the principal sources of supply to the north west Brisbane area, including supply to Ashgrove West, Kelvin Grove, Milton, Roma Street and Makerston Street substations. The transmission line is predominantly overhead, with the final 2.3km long section to Ashgrove West Substation being underground cable.

Potential consultation	Maintaining Reliability of Supply at Ashgrove West
Asset details	Constructed in 1978.
Project driver	Emerging condition, end of technical service life and compliance risks for the Upper Kedron to Ashgrove West underground cables.
Project timing	June 2031.
Proposed network solution	Replacement of the oil-filled cables with new cables in a new easement at an estimated cost of $53 million by June 2031.
Possible non-network solutions	Potential non-network solutions would need to supply approximately 220MW and 2,500MWh per day.
Other possible network solutions	Replacement of existing cables with new cables in the existing easement by June 2031.
Inter-network impact	Powerlink considers the proposed network solutions will not have a material inter-network impact.

Substations

South Pine 275/110kV Substation

Commissioned in 1981 to support regional network expansion, South Pine Substation plays a vital role in the South East Queensland transmission backbone from Central, South West and South East Queensland, providing bulk electricity supply to north Brisbane suburbs and the Brisbane CBD. Located approximately 16km north west of Brisbane's CBD, the substation also includes a 275kV SVC to deliver dynamic reactive power support in the region.

South Pine 275/110kV Transformer

Potential consultation	Maintain Reliability of Supply at South Pine
Asset details	South Pine Substation was constructed in the 1960s with subsequent expansion in the 1970s and 1980s. The relevant transformer asset was installed in 1981.
Project driver	Emerging condition and reliability of supply risks associated with the aged 275/110kV transformer.
Project timing	June 2030.
Proposed network solution	Replacement of the existing 275/110kV transformer at South Pine Substation at an estimated cost of $16 million by June 2030.
Possible non-network solutions	Potential non-network solutions would need to supply approximately 165MW and 1,350MWh per day.
Other possible network solutions	Establishment of a new 275/110kV substation within the north Brisbane area by June 2030.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

South Pine 275kV and SVC secondary systems

Potential consultation	Addressing the 275kV and SVC Secondary Systems Condition Risks at South Pine
Asset details	The 275kV secondary systems at South Pine Substation were installed in 2006. The South Pine SVC was installed in 2008. The SVC provides voltage stability and control services to the transmission network within the greater north Brisbane area. The SVC also provides power systems stability and power oscillation dampening services to support power transfers across the major Queensland 275kV corridors into South East Queensland and QNI.
Project driver	Emerging condition, reliability of supply, and compliance risks associated with the aged components of South Pine 275kV and SVC secondary systems.
Project timing	June 2031.
Proposed network solution	Replacement of the 275kV and SVC secondary systems at an estimated cost of $58 million by June 2031.
Possible non-network solutions	275kV Secondary Systems component: • Potential non-network solutions would need to address the key role that South Pine Substation provides for the connection of 275kV circuits within the South Queensland area. South Pine 110kV West Bus: • Potential non-network solutions would need to supply up to 165MW and 1,350MWh per day. South Pine 110kV East Bus: • Potential non-network solutions would need to supply up to 380MW and 3,340MWh per day. SVC Secondary Systems component: • Potential non-network solutions would need to provide voltage control and stability services for the transmission network supplying the greater north Brisbane area and provide power system dampening services more broadly for the high voltage transmission network and QNI.
Other possible network solutions	Staged replacement of the 275kV secondary systems and full replacement of the SVC secondary systems at South Pine Substation by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

South Pine 110kV Secondary Systems

Potential consultation	Addressing the 110kV Secondary Systems Condition Risks at South Pine
Asset details	Established in 2010.
Project driver	Emerging condition secondary systems compliance risks for the 110kV secondary systems.
Project timing	June 2031.
Proposed network solution	Full replacement of the 110kV secondary systems at South Pine Substation at an estimated cost of $38 million by December 2031.
Possible non-network solutions	Potential non-network solutions would need to address the key role that South Pine Substation provides for the connection of 110kV circuits within the South Queensland area. South Pine 110kV West Bus: • Potential non-network solutions would need to provide up to 165MW and 1,350MWh per day. South Pine 110kV East Bus: • Potential non-network solutions would need to provide up to 380MW and 3,340MWh per day.
Other possible network solutions	Staged replacement of the 110kV secondary systems by June 2031.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Ashgrove West 110/33kV Substation

Ashgrove West Substation was established to meet increased demand in the Brisbane CBD and the expanding residential areas to the north and west of Brisbane.

Potential consultation	Addressing the Secondary Systems Condition Risks at Ashgrove West
Asset details	Established 1979.
Project driver	Emerging condition and 110kV secondary systems compliance risks.
Project timing	December 2029.
Proposed network solution	Full replacement of the 110kV secondary systems at Ashgrove West Substation at an estimated cost of $25 million by December 2029.
Possible non-network solutions	Potential non-network solutions would need to provide up to 220MW and 2,500MWh per day.
Other possible network solutions	Staged replacement on 110kV secondary systems by December 2029.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Goodna 275/110kV Substation

Goodna Substation is located approximately 24km south west of the Brisbane CBD and operates as a bulk supply point to the Energex 33kV network.

Potential consultation	Maintaining Reliability of Supply at Goodna
Asset details	Established in 2006.
Project driver	Condition driven replacement to address obsolescence and condition risks the 275kV and 110kV secondary systems.
Project timing	December 2030.
Proposed network solution	Replacement of 275kV and 132kV secondary systems at an estimated cost of $39 million by December 2030.
Possible non-network solutions	Potential non-network solutions would need to supply up to 180MW and 2,800MWh per day.
Other possible network solutions	Staged replacement of 275kV and 110kV secondary systems by December 2030.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Tennyson 110/33/11kV Substation

Tennyson Substation, located approximately 6km south of the Brisbane CBD, is a 110kV substation fed by three 110kV underground feeders from Rocklea. The substation supplies the Energex local distribution network.

Anticipated consultation	Maintaining Power Transfer Capability and Reliability of Supply at Tennyson
Asset details	Established in 2001.
Project driver	Condition driven replacement to address risks on one of the 110/33/11kV transformers.
Project timing	June 2028.
Proposed network solution	Replacement of Transformer 3 at an estimated cost of $11 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to provide up to 190MW and 2,000MWh per day.
Other possible network solutions	Life extension of Transformer 3 by June 2028.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Greenbank 275kV Substation

Greenbank Substation, located approximately 40km from the coast, is a major node in the transmission network connecting the 330kV and 275kV network from the Southern Downs area into South East Queensland. It is also the major switching station for the 275kV transmission lines supplying the Gold Coast and South Moreton areas.

Potential consultation	Addressing the SVC Secondary Systems Condition Risks at Greenbank
Asset details	The SVC located at Greenbank Substation was installed in 2008. The SVC provides voltage stability and control services to the transmission network within the greater south east Brisbane area. The SVC also provides power systems stability and power oscillation dampening services to support power transfers across the major Queensland 275kV corridors into South East Queensland and across QNI.
Project driver	Emerging condition and reliability of supply risks associated with the aged components of Greenbank SVC secondary systems.
Project timing	June 2030.
Proposed network solution	Replacement of the secondary systems, thyristor valve control systems, and cooling control systems for the SVC installed at Greenbank Substation at an estimated cost of $23 million by June 2030.
Possible non-network solutions	Potential non-network solutions would need to provide voltage control and stability services for the transmission network within the greater south east Brisbane area, and provide stability and power system dampening services more broadly for the high voltage transmission network.
Other possible network solutions	Full replacement of the SVC at Greenbank Substation by June 2030.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[34]

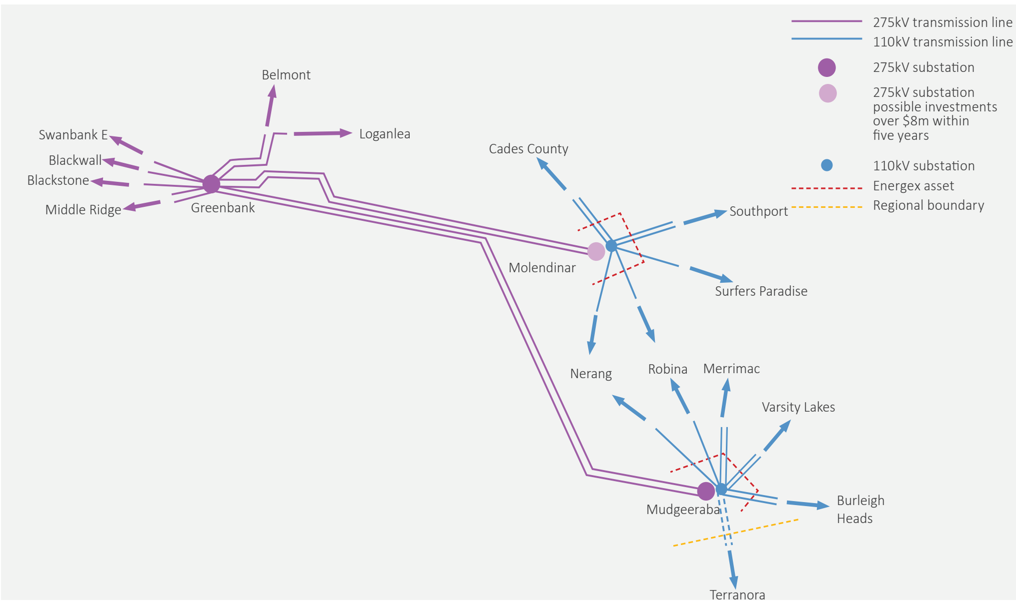
Powerlink has not identified any potential asset retirements in the Moreton zone within the 10-year outlook period.

5.7.6 Gold Coast zone

Existing network

The Powerlink transmission system in the Gold Coast zone was originally constructed in the 1970s and 1980s. The Molendinar and Mudgeeraba substations are the two major injection points into the area via a double circuit 275kV transmission line between Greenbank and Molendinar substations, and two single circuit 275kV transmission lines between Greenbank and Mudgeeraba substations.

Figure 5.17 Gold Coast transmission network



[34] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Possible load driven limitations

Based on Powerlink's Central scenario forecast, there is no additional load driven capacity forecast to be required as a result of load driven network limitations in the Gold Coast zone within the next five years to meet reliability obligations.

Possible network investments within five years

Powerlink anticipates potential network investments above the RIT-T cost threshold may be required to address the risks arising from the condition of assets in the Gold Coast zone within the next five years.

Transmission Lines

Mudgeeraba to Terranora 110kV transmission Line

The existing 110kV transmission line between Mudgeeraba and Terranora substations form the Terranora Interconnector. This transmission line is also a key supply point to loads located in northern New South Wales (NSW). Powerlink owns the section of transmission line from Mudgeeraba Substation to the Queensland-NSW border.

Potential consultation	Addressing Terranora Interconnector Capability
Asset details	Constructed in the mid-1970s.
Project driver	Emerging condition risks within the Powerlink section of Terranora Interconnector due to structural corrosion.
Project timing	June 2028.
Proposed network solution	Refit the Powerlink portion of the existing Mudgeeraba to Terranora 132kV double circuit line at an estimated cost of $8 million by June 2028.
Possible non-network solutions	Potential non-network solutions would need to maintain, as a minimum, existing transmission capability to meet reliability of supply to the northern NSW load area (up to 110MW and 1,500MWh per day) and facilitate inter-regional power transfers.
Other possible network solutions	Rebuild of the Powerlink portion of the Mudgeeraba to Terranora 110kV transmission line.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact, noting there may be the potential for inter-network impacts to occur during construction outage periods. Potential impacts will be analysed closer to identified need timing and as part of the RIT-T consultation process.

Substations

Molendinar 275/110kV Substation

Molendinar 275/110kV Substation, located approximately 75km south west of the Brisbane CBD, is one of two major connection points for supply into the Gold Coast area. The 110kV network from Molendinar to Mudgeeraba links the coastal bulk supply points at Southport, Surfers Paradise and Broadbeach via underground cable. An inland overhead 110kV network supplies Robina and Nerang substations.

Potential consultation	Addressing the Secondary Systems Condition Risks at Molendinar
Asset details	Established in 2003.
Project driver	Emerging condition risks arising from the condition of the 275kV secondary systems.
Project timing	June 2029.
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $53 million.
Possible non-network solutions	Potential non-network solutions would need to provide up to 530MW at peak demand times and up to 7,000MWh per day.
Other possible network solutions	Full replacement of 275kV secondary systems by June 2029.
Inter-network impact	Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible asset retirements[35]

Powerlink has not identified any potential asset retirements in the Gold Coast zone within the 10-year outlook period.

[35] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

5.8 Programs of work

Powerlink monitors and undertakes a regular program of condition assessments of all network assets, including those considered minor value asset classes or sub-populations across the transmission network. This proactive approach ensures that risks arising from asset condition and performance are managed in a safe, reliable and cost-effective manner. When a significant portion of an asset class or sub-population has been identified as requiring investment across the network within a similar timeframe, Powerlink may implement coordinated programs of work. These programs are designed to achieve cost savings from economies of scale and efficiencies in resource allocation, and support timely, proactive replacement.

5.8.1 Transmission line refit works

In mid-2023, Powerlink completed an Asset Reinvestment Review that evaluated targeted investment in life extension of transmission line assets to defer costly rebuilds[36]. Based on the review's recommendations, Powerlink will continue to implement changes to the timing, scope and bundling of proposed transmission line refit works. When identifying potential programs, Powerlink will assess the risks associated with the condition of each transmission line asset individually to ensure solutions are tailored to the specific needs in a prudent and cost-effective manner.

Table 5.9 lists potential transmission line refit works that were identified in the 2024 TAPR currently under consideration for inclusion in Powerlink's line refit programs in the 10-year outlook period.

[36] Powerlink, Asset Reinvestment Review, working group report, June 2023. Also refer to Appendix A for further information on the Asset Reinvestment Review.

Table 5.9 Transmission lines under consideration for inclusion in Powerlink's line refit programs in the 10-year outlook period

Transmission line	Zone	Potential line refit program
Line refit works on the 132kV transmission line between Dan Gleeson and Alan Sherriff substations	Ross	Townsville
Line refit works on the 275kV transmission line between Strathmore and Ross substations	Ross	Townsville
Line refit works on the 132kV transmission line between Nebo Substation and Eton Tee	North	Townsville
Line refit works on the 132kV transmission line between Bouldercombe Substation and Bouldercombe Tee	Central West	Rockhampton-Gladstone
Line refit works on the 132kV transmission line between Bouldercombe Tee and Egans Hill Substation	Central West	Rockhampton-Gladstone
Line refit works on the 275kV transmission line between Wurdong and Boyne Island substations	Gladstone	Rockhampton-Gladstone
Line refit works on the 275kV transmission line between Raglan and Bouldercombe substations	Gladstone	Rockhampton-Gladstone
Line refit works on the 275kV transmission line between Gin Gin and Teebar Creek substations	Wide Bay	Southern
Line refit works on the 275kV transmission line between Gin Gin and Woolooga substations	Wide Bay	Southern
Line refit works on the 275kV transmission line between South Pine and Palmwoods substations	Wide Bay	Southern
Line refit works on the 275kV transmission line between Karana Downs and South Pine substations	Moreton	Southern
Line refit works on the 110kV transmission line between Richlands and Algester substations	Moreton	Southern
Line refit works on the 110kV transmission line between West Darra and Upper Kedron substations	Moreton	Southern
Line refit works on the 275kV transmission line between Bergins Hill and Karana Downs	Moreton	Southern
Line refit works on the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	Moreton	Southern
Line refit works on the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	Moreton	Southern
Line refit works on the 110kV transmission line between Blackstone and Abermain substations	Moreton	Southern
Line refit works on the 275kV transmission line between Greenbank and Mudgeeraba substations	Gold Coast	Southern

5.8.2 Condition-based programs

Table 5.10 identifies potential programs of work over the next five years which will be subject to the RIT-T.

Table 5.10 Potential programs of work over the next five years

Program	Consultation	High level scope	Purpose	Earliest possible commissioning date	Indicative cost ($million)
Capacitive Voltage Transformers Replacement Program	Managing the risk of Capacitive Voltage Transformer Failure	Staged replacement of capacitive voltage transformers at substations throughout Queensland	Maintain supply reliability to Queensland	June 2030	$37m
Direct Current Battery Replacement Program	Managing the Risk of Direct Current Battery Failure	Ongoing program of replacement of Direct Current battery systems at end of life across Powerlink's fleet of substations	Maintain supply reliability to Queensland	This is a proposed ongoing annual program replacing those systems that are at end of life across the Powerlink network.	$60m for the 2027-32 regulatory period
Current Transformer Replacement Program	Addressing the risk of premature Current Transformer failures in Queensland (1)	Staged replacement of current transformers at substations throughout Queensland	Maintain supply reliability to Queensland	June 2031	$87m

Notes:

(1) Powerlink published a PSCR in August 2025 proposing one credible option: replacement of identified current transformers in Northern and Central Queensland by 2029 and replacement of identified current transformers in Southern Queensland by 2031. Submissions are due by 12 November 2025[37].

(2) Powerlink is also progressing a program to install Phase Monitoring Units at a number of sites across the network to meet AEMO requirements.

5.8.3 WAMPAC platform roll-out

Powerlink is progressing with the development and roll out of the WAMPAC platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events.

WAMPAC schemes rapidly detect specific conditions over geographically diverse transmission assets and initiate appropriate action to rapidly respond to changed power system conditions. The platform is capable of operating in sub-second timeframes enabling the system to dynamically respond to changes in the power system and to avoid adverse operating conditions.

WAMPAC schemes have been implemented for system protection services across the CQ-SQ grid section to enhance the resilience and security of the network during non-credible contingencies. In Far North and North Queensland the WAMPAC scheme will soon be in-service to help to manage the impacts of outages on system strength. Powerlink is progressing the implementation in other parts of the network to increase transmission capability, improve security and resilience, and more effectively manage and operate the transmission network during outages.

The planned roll out of WAMPAC across the state is outlined in Table 5.11.

37 Powerlink, Addressing the Risk of Current Transformer Premature Failures in Queensland, PSCR, August 2025.

Table 5.11 WAMPAC platform roll-out

Status	Zone/Grid Section	Application
Completed	CQ-SQ	Improve security and resilience under non-credible contingencies (tranche 1)
	Far North and North Queensland	Managing system strength and reduce impacts of network outages
In progress	CQ-SQ	Improve security and resilience under non-credible contingencies (tranche 2)
	Surat	Improve security and resilience under non-credible contingencies
Short to longer term	Management of extreme events	Improve security and resilience under non-credible contingencies, interconnectors, consideration of use with frequency management
	Various Grid Sections	Run-back schemes to provide additional network capacity of the shared grid (e.g. Virtual Transmission Lines)
	N-2 for double circuit generation connection	Increase hosting capacity for new generation double circuits
	Various locations	Provision of non-firm capacity to urgent load connections (e.g. electrification, hydrogen, etc)
	Various locations	Anti-islanding capability (various timings)

5.9 Supply / demand balance

The outlook for the supply / demand balance for the Queensland region was published by AEMO in the 2025 Electricity Statement of Opportunities (ESOO). Interested parties who require information regarding future supply / demand balance should consult the ESOO.

5.10 Existing interconnectors

Powerlink and Transgrid completed a RIT-T in December 2019 to expand transmission transfer capacity between Queensland and New South Wales. The recommended QNI Minor Project included uprating the 330kV Liddell to Tamworth 330kV lines and installing SVCs at Tamworth and Dumaresq substations and capacitor banks at Tamworth, Armidale and Dumaresq substations. Transgrid completed commissioning these works by May 2022 and inter-network testing activities, as required by clause 5.7.7 of the NER, are in the final stages, resulting in increased capacity in both north and south flows.

5.11 Transmission lines approaching end of technical service life beyond the 10-year outlook period

As transmission lines approach their expected end of technical service life, Powerlink conducts detailed planning studies to determine each asset's enduring need. These studies consider the asset condition, risk and alignment with future investment or network optimisation strategies. Possible options include line refit, targeted and/or staged refit or replacement, upfront replacement or rebuild, network reconfiguration, non-network alternatives, asset de-rating or retirement.

The information in Table 5.12 which goes five years beyond the 10-year outlook period of the 2025 TAPR, is provided in good faith[38] as a snapshot and is the best information available at the time of TAPR publication. Transmission equipment and line ratings information is available on AEMO's website and can also be accessed via the link in the TAPR Portal.

Proponents who wish to connect to Powerlink's transmission network are strongly encouraged to contact NetworkAssessments@powerlink.com.au in the first instance.

[38] For completeness, refer to Powerlink's Disclaimer inside the front cover.

Table 5.12 Transmission lines approaching end of technical service: 10-15 years (July 2035 to June 2040)

Region	Zone	Feeder	Voltage	General location
Northern	Far North	7227	132kV	Between Cairns and Woree substations
Northern	Far North	7191, 7192	132kV	Between Kareeya and Chalumbin substations
Northern	Far North	876, 877	275kV	Between Chalumbin and Woree substations
Northern	Ross	8858	275kV	Between Strathmore and Ross substations
Northern	Ross	7130, 7131	132kV	Between Clare South and Townsville South substations
Northern	North	7120, 7304, 7305	132kV	Between Nebo and Pioneer Valley substations
Northern	North	834	275kV	Between Nebo and Broadsound substations
Northern	North	7152	132kV	Between Pioneer Valley and Alligator Creek substation
Northern	North	7119	132kV	Between Nebo and Alligator Creek substations
Northern	North	7238	132kV	Between Pioneer Valley and Mackay substations
Northern	North	856	275kV	Between Stanwell and Broadsound substations
Northern	Central West	820	275kV	Between Bouldercombe and Broadsound substations
Northern	Central West	821	275kV	Between Bouldercombe and Nebo substations
Central	Central West	833	275kV	Between Broadsound and Lilyvale substations
Central	Central West	7370, 7369	132kV	Between Moranbah and Goonyella Riverside substations
Central	Central West	7150	132kV	Between Lilyvale and Dysart substations
Central	Central West	7109	132kV	Between Baralaba and Calvale substations
Central	Central West	7110	132kV	Between Calvale and Moura substations
Central	Central West	7112	132kV	Between Baralaba and Moura substations
Central	Central West	7124	132kV	Between Moranbah and Dysart substations
Central	Central West	848, 849	275kV	Between Stanwell and Bouldercombe substations
Central	Gladstone	8875	275kV	Between Raglan and Larcom Creek substations
Central	Gladstone	7145, 7146	132kV	Between Calliope River and Boyne Island substations
Central	Gladstone	871	275kV	Between Calvale and Wurdong substations
Central	Gladstone	8859	275kV	Between Calliope River and Larcom Creek substations
Central	Gladstone	8877, 8878	275kV	Between Gladstone and Calliope River substations
Central	Gladstone	7194	132kV	Between Gladstone and Calliope River substations
Central	Gladstone	7145, 7146	132kV	Between Calliope River and Boyne Island substations
Southern	Wide Bay	8850	275kV	Between Woolooga and Teebar Creek substations
Southern	Wide Bay	819	275kV	Between Teebar Creek and Wurdong substations
Southern	South West	831	275kV	Between Tarong and Middle Ridge substations
Southern	Moreton	827	275kV	Between Tarong and Blackwall substations
Southern	Moreton	832	275kV	Between Tarong and South Pine substations
Southern	Moreton	825	275kV	Between Mt England and South Pine substations
Southern	Moreton	805	275kV	Between Swanbank and Greenbank substations
Southern	Moreton	829	275kV	Between Loganlea and Belmont substations
Southern	Moreton	8822	275kV	Between Greenbank and Belmont substations

Network capability and performance

06

This chapter discusses how changes to Queensland's generation mix and demand profiles impact the power flows across the transmission network.

Key highlights

- Generation commitments since the 2024 Transmission Annual Planning Report (TAPR) added 1,026 megawatts (MW) to Queensland's semi-scheduled variable renewable energy (VRE[1]) generation capacity, taking the total existing and committed semi-scheduled VRE generation capacity to 8,290MW.
- Storage commitments since the 2024 TAPR added 1,530MW of two-hour Battery Energy Storage Systems (BESS). Total energy storage from existing and committed BESS now exceeds 6 gigawatt hours (GWh).
- Record maximum and minimum transmission delivered demands were experienced in South West, Moreton, Gold Coast and Bulli zones during 2024/25.
- The transmission network has performed strongly during 2024/25, with Queensland grid sections largely unconstrained.
- Powerlink is continuing to develop the Wide Area Monitoring Protection and Control (WAMPAC) platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events.

6.1 Introduction

Network capability and performance is central to ensuring the reliability and efficiency of the energy system, and for integrating new generation into the grid. The capability of Powerlink's transmission network is dependent on several factors:

- Weather – Queensland's transmission network is utilised more during summer than winter. During higher summer temperatures transmission plant has lower power carrying capability which is also when demand is higher (refer to Figure 2.15).
- The location and pattern of generation dispatch – future generation dispatch patterns, interconnector and inter-zonal flows are uncertain and will vary substantially due to output of VRE generation.
- Outages – power flows can also vary substantially with planned or unplanned outages of transmission network elements. Power flows may also be higher at times of local area or zone maximum demands[2] and/or when embedded generation output is lower.

The National Electricity Rules (NER) require:

- Transmission Network Service Providers (TNSPs) to analyse the expected future operation of the transmission network, considering relevant loads, future generation, market network service and other relevant data[3]
- TNSPs to conduct an annual planning review, which includes a review of the adequacy of connection points and relevant parts of the transmission network[4]
- the TAPR to include information on control schemes in place to manage network stability and identify the need for new or altered controls[5].

Accordingly, this chapter provides both the historic performance as well as information on the changing generation, load and network flows. This includes:

- an outline of existing and committed generation and storage capacity over the next three years
- single line diagrams of the existing high voltage (HV) network configuration
- zonal energy transfers for the two most recent years
- duration curves of transmission delivered demand for the five most recent years
- duration curves of inter-zonal power flows for the five most recent years
- constraint times for key sections of the transmission network
- a qualitative explanation of factors affecting power transfer capability at key sections of the transmission network

1 In this chapter both VRE and inverter-based resource (IBR) terms are used. VRE refers to renewable energy sources whose output varies with ambient conditions and cannot be fully controlled (e.g. wind and solar photovoltaic (PV)). IBR refers to generation technologies that connect to the grid through power electronic inverters (e.g. wind, solar PV and battery storage).
2 Refer to Table 2.12.
3 National Electricity Rules (NER), clause 5.12.1(a).
4 NER, clause 5.12.1(b)(2).
5 NER, clauses 5.12.2(c)(9) and (9A).

- a high-level summary of loss of supply events caused by credible contingencies in each zone
- double circuit transmission lines categorised as vulnerable by the Australian Energy Market Operator (AEMO)
- a summary of network control facilities configured to disconnect load because of non-credible events.

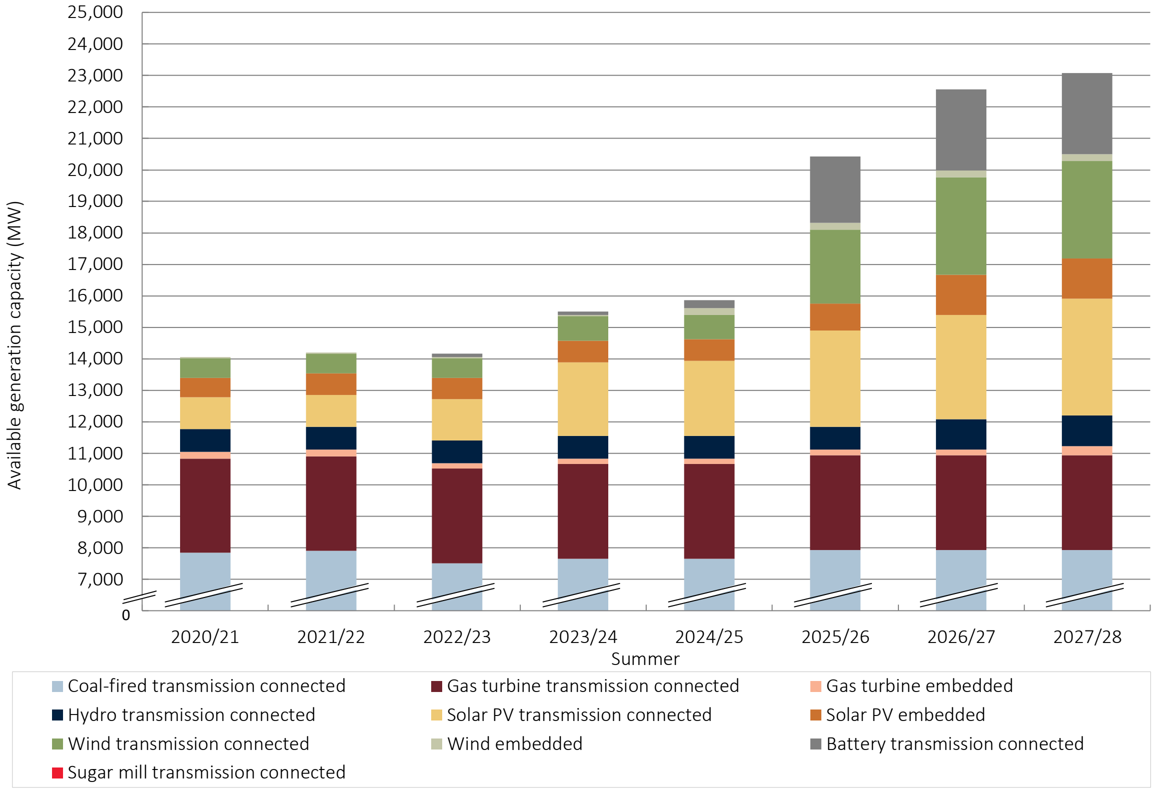
6.2 Available generation capacity

Scheduled generation in Queensland is predominantly a combination of coal fired, gas turbine and hydro-electric generators, with an increasing share coming from battery and pumped hydro energy storage (PHES) systems. Semi-scheduled generation in Queensland is a combination of wind and solar generation.

Powerlink applies AEMO's definition of 'committed' projects from the System Strength Impact Assessment Guidelines. The definition of 'committed' includes that AEMO is satisfied the project meets the requirements of the NER, a connection agreement is in place and a system strength remediation scheme, where required, has been finalised[6].

During 2024/25, commitments have added 1,027MW of semi-scheduled VRE capacity, taking Queensland's semi-scheduled VRE generation capacity to 8,291MW. In addition, 1,530MW of BESS capacity has been committed, taking the total BESS capacity to 2,590MW. Figure 6.1 illustrates the actual and expected changes to available and committed large-scale generation capacity in Queensland from summer 2020/21 to summer 2027/28.

Figure 6.1 Summer available generation capacity by energy source



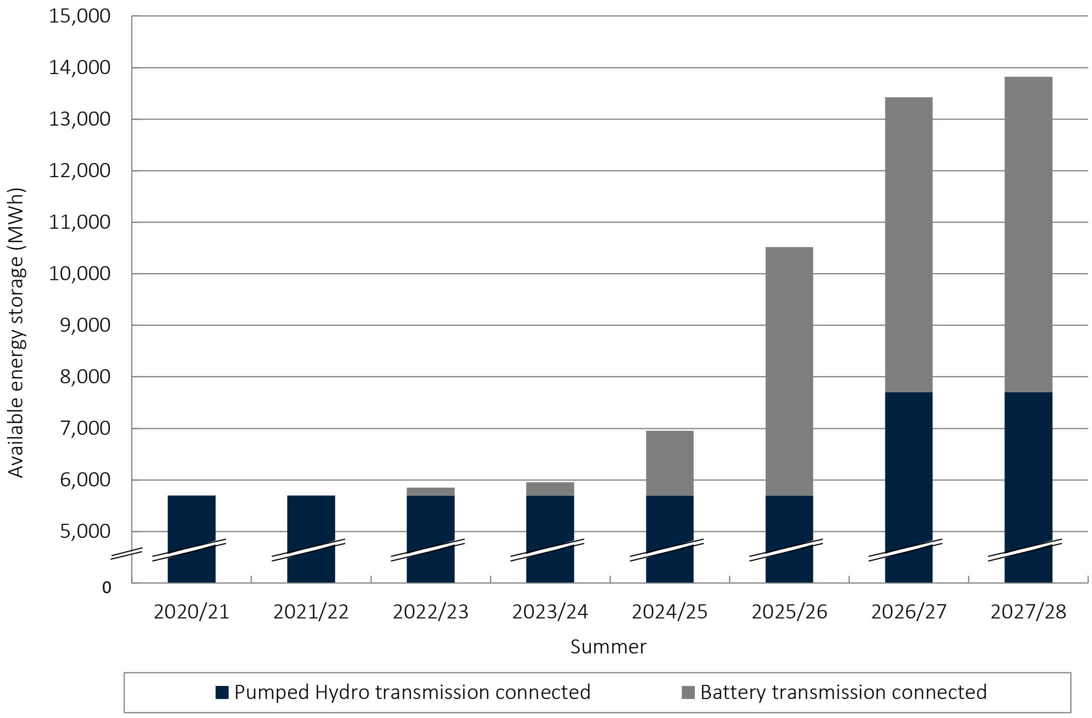
Storage is essential to smooth out variations in supply from VRE generation. Prior to 2022, Wivenhoe Pumped Storage Hydro Power Station was the only transmission-connected energy storage in Queensland. Since then, seven grid-connected batteries have been commissioned or are in commissioning. Additionally, the Punchs Creek Solar Farm recently became the first committed solar generation project to incorporate battery storage and connect to the Powerlink network.

The Kidston Pumped Storage Hydro Project is committed and under construction, and various pumped hydro stations are in the development pipeline. Figure 6.2 shows the recent increases in energy storage capacity and the new capacity that will be available in the coming years based on project commitments.

Total energy storage capacity connected or committed to be connected to the network now exceeds 13GWh with just over 6GWh coming from battery storage.

6 AEMO, System Strength Impact Assessment Guidelines, Version 2.2, June 2024, page 5.

Figure 6.2 Available storage capacity by type



6.2.1 Existing and committed transmission connected and direct connect embedded generation

Table 6.1 summarises the available generation capacity of power stations connected or committed to be connected to Powerlink's transmission network (including the non-scheduled generators at Yarwun, Invicta and Koombooloomba), or to Powerlink's direct connect customers.

Semi-scheduled transmission connected storage at Aldoga Solar Farm and Punchs Creek Solar Farm and BESS have reached committed status since the 2024 TAPR.

Scheduled transmission connected storage at Tarong, Supernode 1 & 2, Brendale and Swanbank BESS have reached committed status since the 2024 TAPR.

Non-scheduled, semi-scheduled and scheduled generators are treated differently in AEMO's central dispatch process[7].

Information in this table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website. Powerlink's Register of Large Generator Connections, which includes information on generators connected to our network, is available on Powerlink's website[8].

[7] AEMO Fact Sheet: Visibility of the Power System.
[8] NER, rule 5.18A.

Table 6.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers

Generator	Location	Available capacity MW generated Summer 2025/26	Winter 2026	Summer 2026/27	Winter 2027	Summer 2027/28	Winter 2028
Coal-fired (1)							
Stanwell	Stanwell	1,460	1,460	1,460	1,460	1,460	1,460
Gladstone	Calliope River	1,680	1,680	1,680	1,680	1,680	1,680
Callide B	Calvale	700	700	700	700	700	700
Callide Power Plant	Calvale	868	932	868	932	868	932
Tarong North	Tarong	443	443	443	443	443	443
Tarong	Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Kogan Creek	Kogan Creek Power Station (PS)	710	750	710	750	710	750
Millmerran	Millmerran PS	670	852	670	852	670	852
Total coal-fired		7,931	8,217	7,931	8,217	7,931	8,217
Gas-fired (1)							
Townsville 132kV	Townsville GT PS	150	165	150	165	150	165
Mt Stuart	Townsville South	387	400	387	400	387	400
Yarwun (2)	Yarwun	160	155	160	155	160	155
Condamine (3)	Columboola	139	144	139	144	139	144
Braemar 1	Braemar	501	543	501	543	501	543
Braemar 2	Braemar	480	519	480	519	480	519
Darling Downs	Braemar	563	630	563	630	563	630
Oakey (4)	Tangkam	288	346	288	346	288	346
Swanbank E	Swanbank E PS	350	365	350	365	350	365
Total gas turbine		3,018	3,267	3,018	3,267	3,018	3,267
Hydro-electric							
Barron Gorge	Kamerunga	66	66	66	66	66	66
Kareeya (including Koombooloomba) (5)	Chalumbin	93	93	93	93	93	93
Wivenhoe (6)	Mt. England	570	570	570	570	570	570
Kidston Pumped Storage Hydro (6)	Kidston		250	250	250	250	250
Total hydro-electric		729	729	979	979	979	979
Solar PV (7)							
Ross River	Ross	116	116	116	116	116	116
Sun Metals (3)	Townsville Zinc	121	121	121	121	121	121
Haughton	Haughton River	100	100	100	100	100	100
Clare	Clare South	100	100	100	100	100	100
Whitsunday	Strathmore	57	57	57	57	57	57

Table 6.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers (*continued*)

Generator	Location	Available capacity MW generated Summer 2025/26	Winter 2026	Summer 2026/27	Winter 2027	Summer 2027/28	Winter 2028
Hamilton	Strathmore	57	57	57	57	57	57
Daydream	Strathmore	150	150	150	150	150	150
Hayman	Strathmore	50	50	50	50	50	50
Rugby Run	Moranbah	65	65	65	65	65	65
Broadsound	Broadsound	296	296	296	296	296	296
Lilyvale	Lilyvale	100	100	100	100	100	100
Aldoga	Larcom Creek	387	387	387	387	387	387
Moura	Moura	82	82	82	82	82	82
Woolooga Energy Park	Woolooga	176	176	176	176	176	176
Blue Grass	Chinchilla	148	148	148	148	148	148
Columboola	Columboola	162	162	162	162	162	162
Gangarri	Wandoan South	120	120	120	120	120	120
Wandoan	Wandoan South	125	125	365	365	365	365
Edenvale Solar Park	Orana	146	146	146	146	146	146
Western Downs Green Power Hub	Western Downs	400	400	400	400	400	400
Punchs Creek (8)	Punchs Creek				400	400	400
Darling Downs	Braemar	108	108	108	108	108	108
Total solar PV		3,066	3,066	3,306	3,706	3,706	3,706
Wind (7)							
Mt Emerald	Walkamin	180	180	180	180	180	180
Kaban	Tumoulin	152	152	152	152	152	152
Lotus Creek	Glencoe			276	276	276	276
Clarke Creek	Broadsound	440	440	440	440	440	440
Boulder Creek	Muranu			221	221	221	221
Wambo	Halys	245	245	245	245	245	245
Wambo 2	Halys		247	247	247	247	247
Coopers Gap	Coopers Gap	440	440	440	440	440	440
MacIntyre	Tummaville	890	890	890	890	890	890
Total wind		2,347	2,594	3,091	3,091	3,091	3,091
Battery (7)							
Bouldercombe 2 hour	Bouldercombe	50	50	50	50	50	50
Woolooga 2 hour	Woolooga		200	200	200	200	200
Wandoan 1.5 hour	Wandoan South	100	100	100	100	100	100

Table 6.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers (*continued*)

Generator	Location	Available capacity MW generated Summer 2025/26	Winter 2026	Summer 2026/27	Winter 2027	Summer 2027/28	Winter 2028
Tarong 2 hour	Tarong	300	300	300	300	300	300
Chinchilla 2 hour	Western Downs	100	100	100	100	100	100
Western Downs 2 hour	Western Downs	255	510	510	510	510	510
Ulinda Park 2 hour	Western Downs	155	155	155	155	155	155
Brendale 2 hour	South Pine	205	205	205	205	205	205
Supernode 1 and 2 2 hour and 4 hour	South Pine	520	520	520	520	520	520
Swanbank 2 hour	Blackstone	250	250	250	250	250	250
Greenbank 2 hour	Greenbank	200	200	200	200	200	200
Total battery		2,135	2,590	2,590	2,590	2,590	2,590
Sugar mill							
Invicta (5)	Invicta Mill	0	34	0	34	0	34
Total sugar mill		0	34	0	34	0	34
Total all stations		**19,226**	**20,747**	**20,915**	**21,884**	**21,315**	**21,884**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than power station net sent out nominal capacity due to station auxiliary loads and step up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) Yarwun is a non-scheduled generator but is required to comply with some of the obligations of a scheduled generator.

(3) Condamine and Sun Metals are direct connected embedded generators.

(4) Oakey Power Station is an open-cycle, dual-fuel, gas-fired power station. The generated capacity quoted is based on gas fuel operation.

(5) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(6) Wivenhoe and Kidston Pumped Storage Hydro are shown at full capacity. However, output can be limited depending on water storage levels.

(7) VRE generators and batteries are shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

(8) Includes battery storage behind the connection point.

6.2.2 Existing and committed scheduled and semi-scheduled distribution connected embedded generation

Table 6.2 summarises the available generation capacity of embedded scheduled and semi-scheduled power stations connected or committed to be connected to Queensland's distribution network.

Scheduled embedded generation Lockyer Energy Project has reached committed status since the 2024 TAPR.

Information in this table has been provided to AEMO by the owners of the generators. Further details on registration status and generator capacities can be found on AEMO's website.

Table 6.2 Available generation capacity – existing and committed scheduled or semi-scheduled generators connected to the Ergon Energy and Energex distribution networks

Generator	Location	Available capacity MW generated					
		Summer 2025/26	Winter 2026	Summer 2026/27	Winter 2027	Summer 2027/28	Winter 2028
Combustion turbine (1)							
Townsville 66kV	Townsville GT PS	78	82	78	82	78	82
Barcaldine	Barcaldine	32	37	32	37	32	37
Roma	Roma	54	68	54	68	54	68
Lockyer Energy Project	Gatton					116	116
Total combustion turbine		164	187	164	187	280	303
Solar PV (2)							
Kidston	Kidston	50	50	50	50	50	50
Kennedy Energy Park	Hughenden	15	15	15	15	15	15
Collinsville	Collinsville North	42	42	42	42	42	42
Clermont	Clermont	75	75	75	75	75	75
Emerald	Emerald	72	72	72	72	72	72
Middlemount	Lilyvale	26	26	26	26	26	26
Bundaberg	Gin Gin		78	78	78	78	78
Bullyard	Gin Gin			97	97	97	97
Banksia	Isis			60	60	60	60
Aramara	Aramara				104	104	104
Susan River	Maryborough	75	75	75	75	75	75
Childers	Isis	56	56	56	56	56	56
Munna Creek	Kilkivan	120	120	120	120	120	120
Kingaroy	Kingaroy	40	40	40	40	40	40
Maryrorough	Yarranlea	27	27	27	27	27	27
Yarranlea	Yarranlea	103	103	103	103	103	103
Oakey 1	Oakey	25	25	25	25	25	25
Oakey 2	Oakey	55	55	55	55	55	55
Warwick	Warwick	64	64	64	64	64	64
Gunsynd	Waggamba		94	94	94	94	94
Total solar PV		845	1,017	1,174	1,278	1,278	1,278
Wind (2)							
Kennedy Energy Park	Hughenden	43	43	43	43	43	43
Dulacca	Roma	173	173	173	173	173	173
Total wind		216	216	216	216	216	216
Total all stations		**1,225**	**1,420**	**1,554**	**1,681**	**1,774**	**1,797**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than the power station's net sent out nominal capacity due to station auxiliary loads and step up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) VRE generators shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

6.2.3 Information of generation and storage projects yet to be committed

The information in tables 6.1 and 6.2 relate only to existing and committed projects in Queensland. Details of projects at earlier stages of development are available from the Queensland Government's Power Plants Map of Queensland or from AEMO's NEM Generation Maps.

6.3 Network capacity and security

6.3.1 Increasing capacity of the transmission system

Powerlink is continuing to develop the WAMPAC platform to maximise the capability of the network and provide an additional layer of security and resilience to system disturbances and events.

WAMPAC schemes rapidly detect abnormal system conditions across geographically diverse transmission assets and initiates appropriate action to adapt to system conditions. For example, changing the network configuration or altering generation and load characteristics. The speed of operation of WAMPAC enables the platform to be effective in sub-second timeframes and can remediate dynamic conditions to minimise disruption and to significantly reduce the probability of cascading failure.

WAMPAC has been implemented for system protection services across the Central Queensland to South Queensland (CQ-SQ) grid section. Further applications for the technology have been implemented in Northern Queensland to more effectively manage and operate the transmission network during outages. It is also anticipated that WAMPAC will be instrumental in increasing the hosting capacity and mitigating the impacts of network contingencies and planned outages in the future.

New technology is being introduced to optimise the performance and capacity of the high voltage network. Detailed assessments have been completed for the adoption of advanced conductor technology, and Powerlink anticipates utilising this technology within 275 kilovolt (kV) transmission infrastructure in Central and South Queensland to increase the thermal ratings of transmission.

In addition, field trials are underway to test equipment that enables real-time ratings for overhead conductor lines. This takes into account the prevailing weather conditions on critical spans. The aim is to increase the thermal capability of the transmission network the vast majority of the time during periods of elevated wind speeds or reduced ambient temperature or solar irradiation. The Bureau of Meteorology (BOM) has provided advice and weather data to help inform the scope of the trial.

6.3.2 Managing non-credible network events

Powerlink participated in the 2025 General Power System Risk Review (GPSRR), published by AEMO in July 2025[9]. Powerlink continues to work with AEMO to progress work on the priority risks identified in the report.

Work is continuing for the following recommendations from previous years:

- Expansion of WAMPAC for the non-credible loss of both Calvale-Halys 275kV lines. The scheme will be improved to manage higher flows on the CQ-SQ grid section.
- Implementation of a new WAMPAC scheme to manage the non-credible loss of both Columboola to Western Downs 275kV lines resulting in the loss of all loads in the Surat zone.
- The design of the Over Frequency Generator Shedding (OFGS) scheme for Queensland is finalised and Powerlink is engaging with generators to implement the settings.

Powerlink owns other network control facilities that may disconnect load following a non-credible contingency to minimise or reduce the consequences of such events. A list of these facilities is provided in Table 6.3.

[9] AEMO, 2025 General Power System Risk Review, July 2025.

Table 6.3 Powerlink network control facilities configured to disconnect load as a consequence of non-credible events during system normal conditions

Scheme	Purpose
Far North Queensland (FNQ) Under Voltage Load Shed (UVLS) scheme	Minimise risk of voltage collapse in FNQ
North Goonyella Under Frequency Load Shed (UFLS) relay	Raise system frequency
Dysart UVLS	Minimise risk of voltage collapse in Dysart area
Eagle Downs UVLS	Minimise risk of voltage collapse in Eagle Downs area
Boyne Island UFLS relay	Raise system frequency
Queensland UFLS inhibit scheme	Minimise risk of Queensland to New South Wales Interconnector (QNI) separation for an UFLS event for moderate to high southern transfers on QNI compared to Queensland demand
CQ-SQ N-2 WAMPAC scheme	Minimise risk of CQ-SQ separation for a non-credible loss of the Calvale to Halys 275kV double circuit transmission line
Tarong UFLS relay	Raise system frequency
Middle Ridge UFLS relays	Raise system frequency
Mudgeeraba Emergency Control Scheme (ECS)	Minimise risk of voltage collapse in the Gold Coast zone

6.4 Existing network configuration

Figures 6.3 to 6.6 illustrate Powerlink's system intact network as of July 2025.

Figure 6.3 Existing HV network, July 2025 – North Queensland

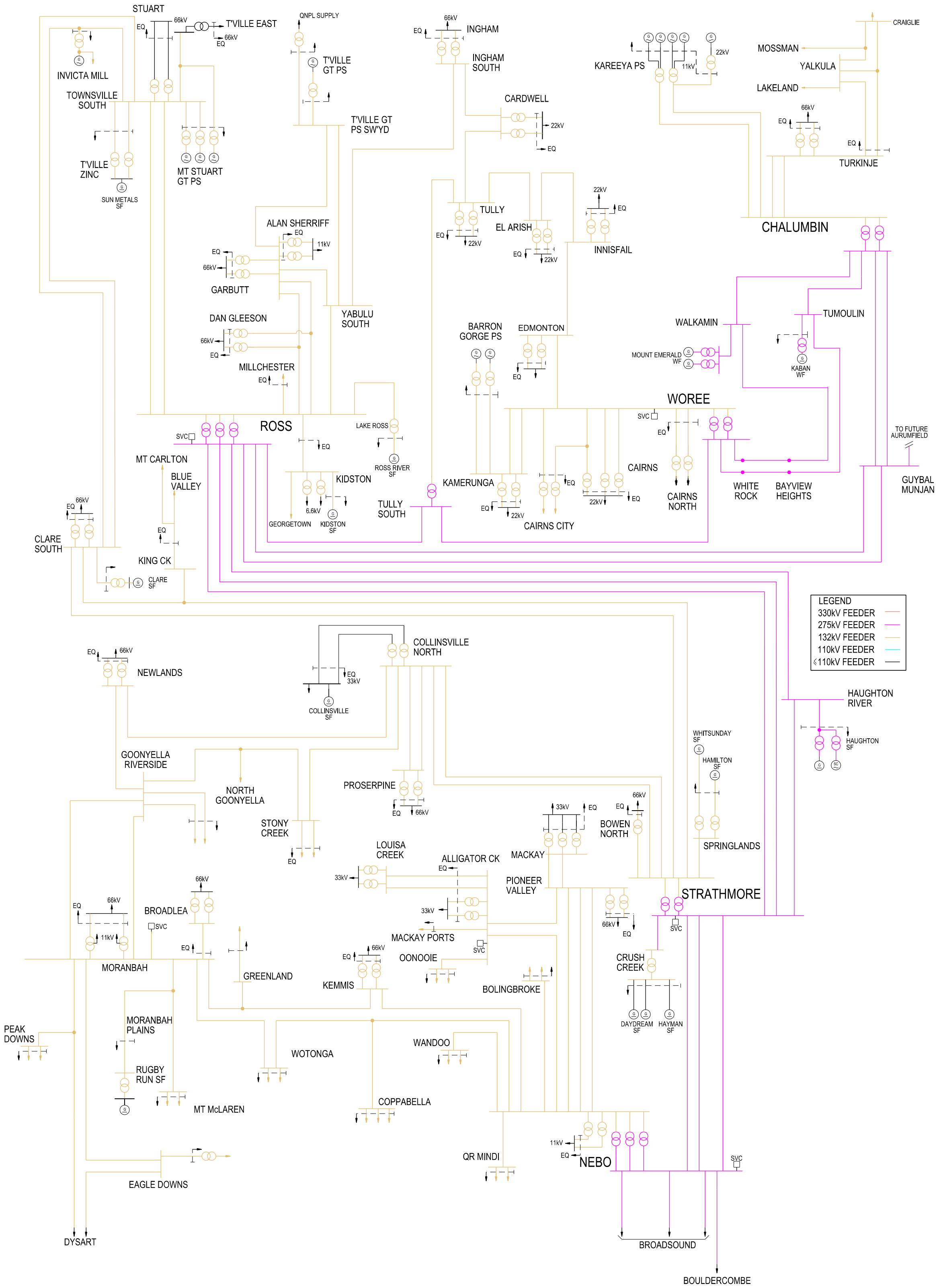


Figure 6.4 Existing HV network, July 2025 – Central Queensland

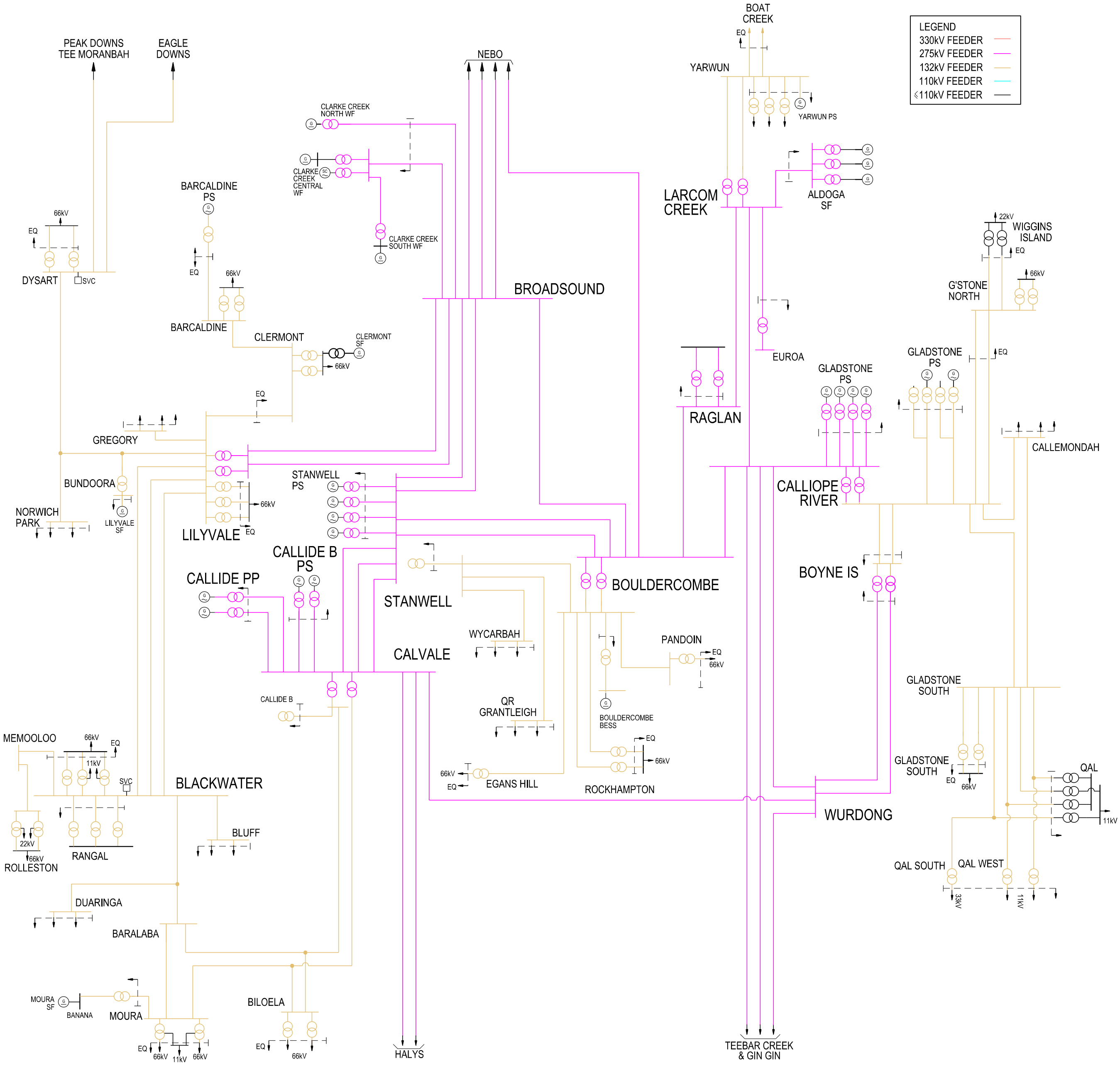


Figure 6.5 Existing HV network, July 2025 – South West Queensland

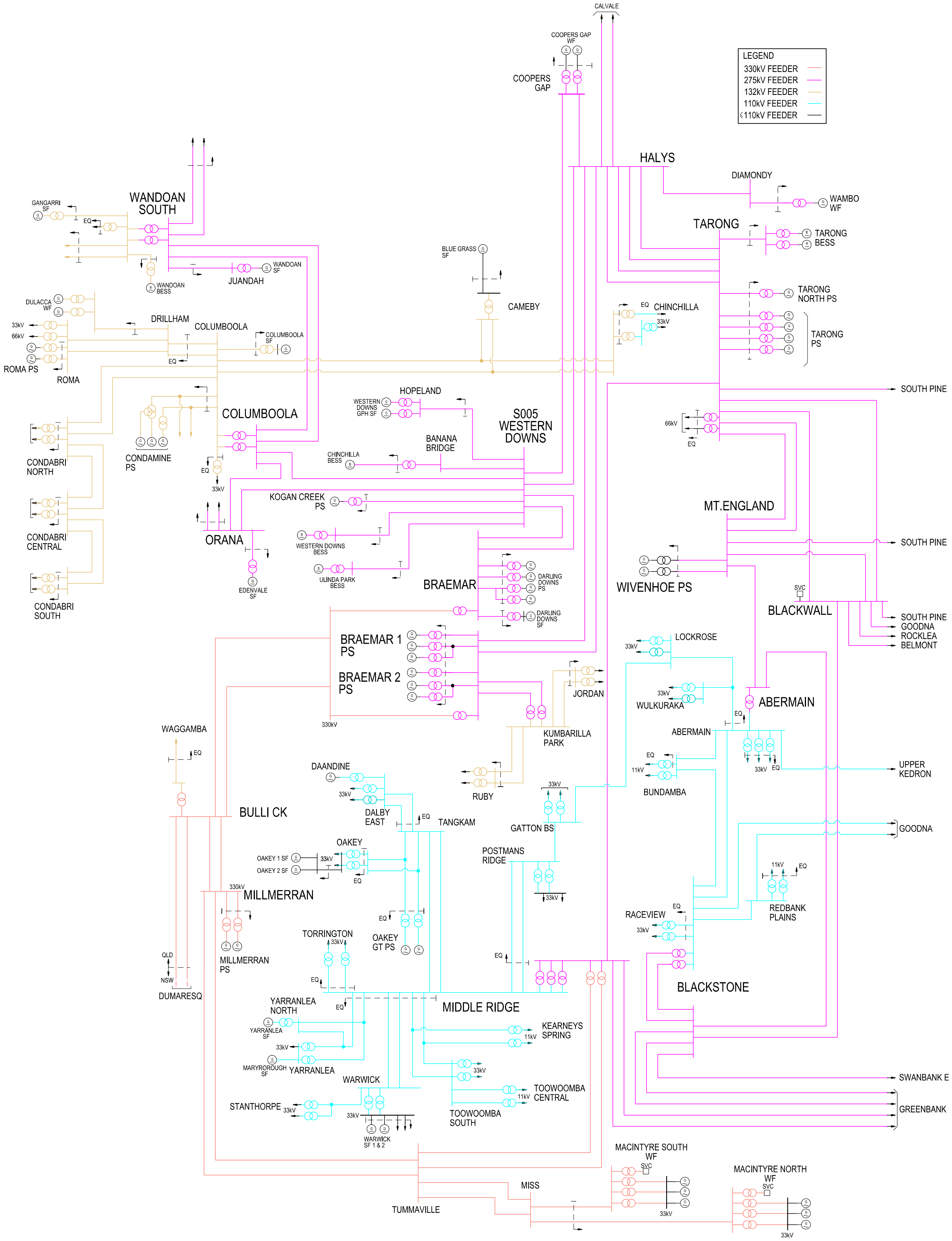
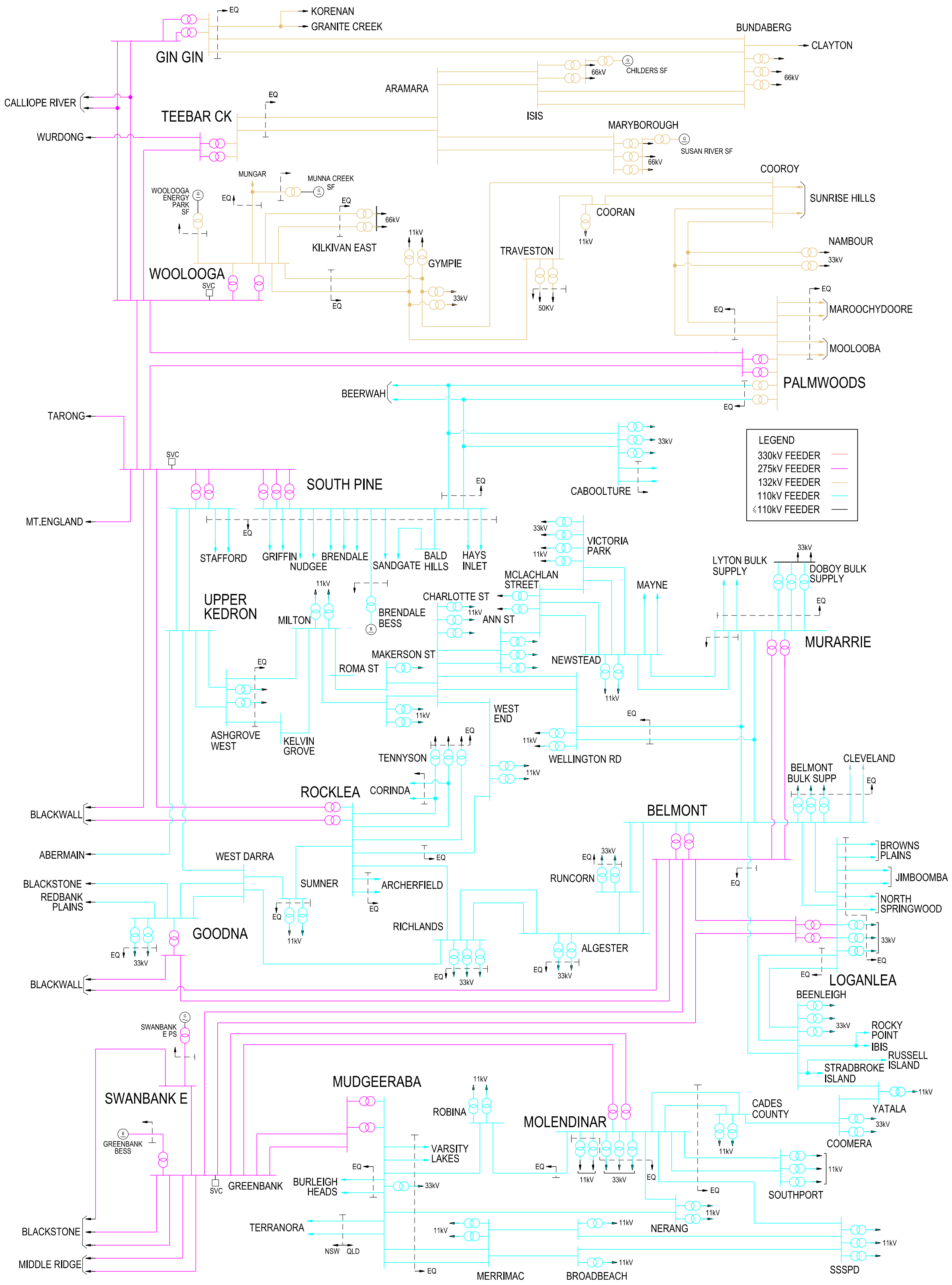


Figure 6.6 Existing HV network, July 2025 – South East Queensland



6.5 Transfer capability

6.5.1 Location of grid sections

Powerlink defines a number of grid sections on the main transmission system. The grid sections are used to measure power transfer between zones (refer to Figure G.1 of Appendix G) and define the maximum secure power transfer capability between zones. This allows the assessment of network capability and to forecast limitations in a structured manner.

The maximum power transfer capability for these sections may be determined by factors such as transient stability, voltage stability, thermal plant ratings, or protection relay load limits. Powerlink develops and maintains limit equations for these grid sections to quantify maximum secure power transfer. AEMO then incorporates these limit equations into constraint equations within the National Electricity Market Dispatch Engine (NEMDE). Table G.2 and Figure G.1 in Appendix G define and illustrate the location of relevant grid sections on the Queensland network.

6.5.2 Determining transfer capability

Transfer capability across each grid section varies with different system operating conditions. Transfer limits in the National Electricity Market (NEM) cannot generally be expressed as a single number. Instead, Transmission Network Service Providers (TNSPs) define the capability of their network using multi-term equations that define the relationship between system operating conditions and allowable flows.

These equations are implemented into NEMDE, following AEMO's due diligence, to ensure secure and optimal dispatch of generation. In Queensland, the transfer capability is highly dependent on which generators are in-service and their dispatch level. The limit equations maximise transmission capability available to electricity market participants under prevailing system conditions.

Limit equations derived by Powerlink are provided in Appendix H. These limit equations are current at the time of publication of this TAPR but will change over time with demand, generation and network development, and/or network reconfiguration. For example, the commissioning of the third 275kV circuit into Cairns in late 2023 triggered an update to the FNQ grid section voltage stability equation. Expected limit improvements for committed works are incorporated in all future planning.

6.6 Grid section performance

This section provides a summary of the changing flows on key grid sections within the Queensland network, along with system conditions that significantly affect their transfer capability. Grid section transfers are affected by load, generation and transfers to neighbouring zones. Historical transfer duration curves for the past five years are included for each grid section.

In addition to grid section transfer duration curves, data is provided on how often the associated constraint equations have bound over the past decade. These are categorised as occurring during intact or outage conditions, based on AEMO's constraint description.

Constraint times typically occur when constraint equations bind due to generator unavailability, network outages, unfavourable dispatches and/or high loads. Occurrences associated with network support agreements are excluded, as binding constraints whilst network support is dispatched are not classed as market congestion. While high constraint times do not directly indicate market cost impact, they provide a key signal for assessing the economics for relieving congestion.

Figures 6.7 and 6.8 provide 2023/24 and 2024/25 zonal energy flows. This includes transmission connected generation, major embedded generators, transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers as well as energy transfers for each grid section. Figure 6.9 shows the changes in energy transfers from 2023/24 to 2024/25. These figures assist in the explanation of differences between grid section transfer duration curves over the last two years. A breakdown of transmission connected generation by generation type and zone is provided in Table G.3 in Appendix G.

Figure 6.7 2023/24 zonal electricity transfers (GWh)

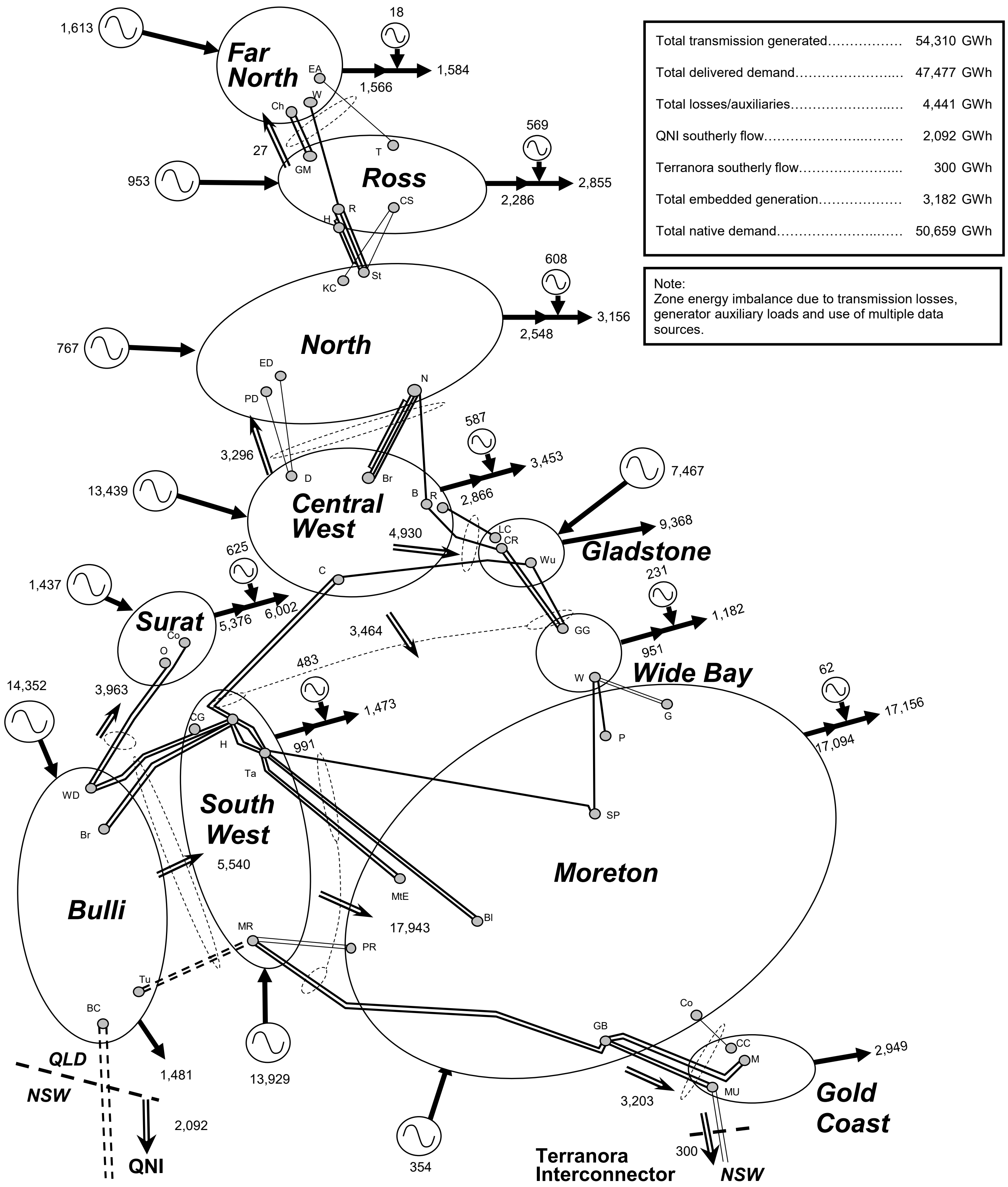
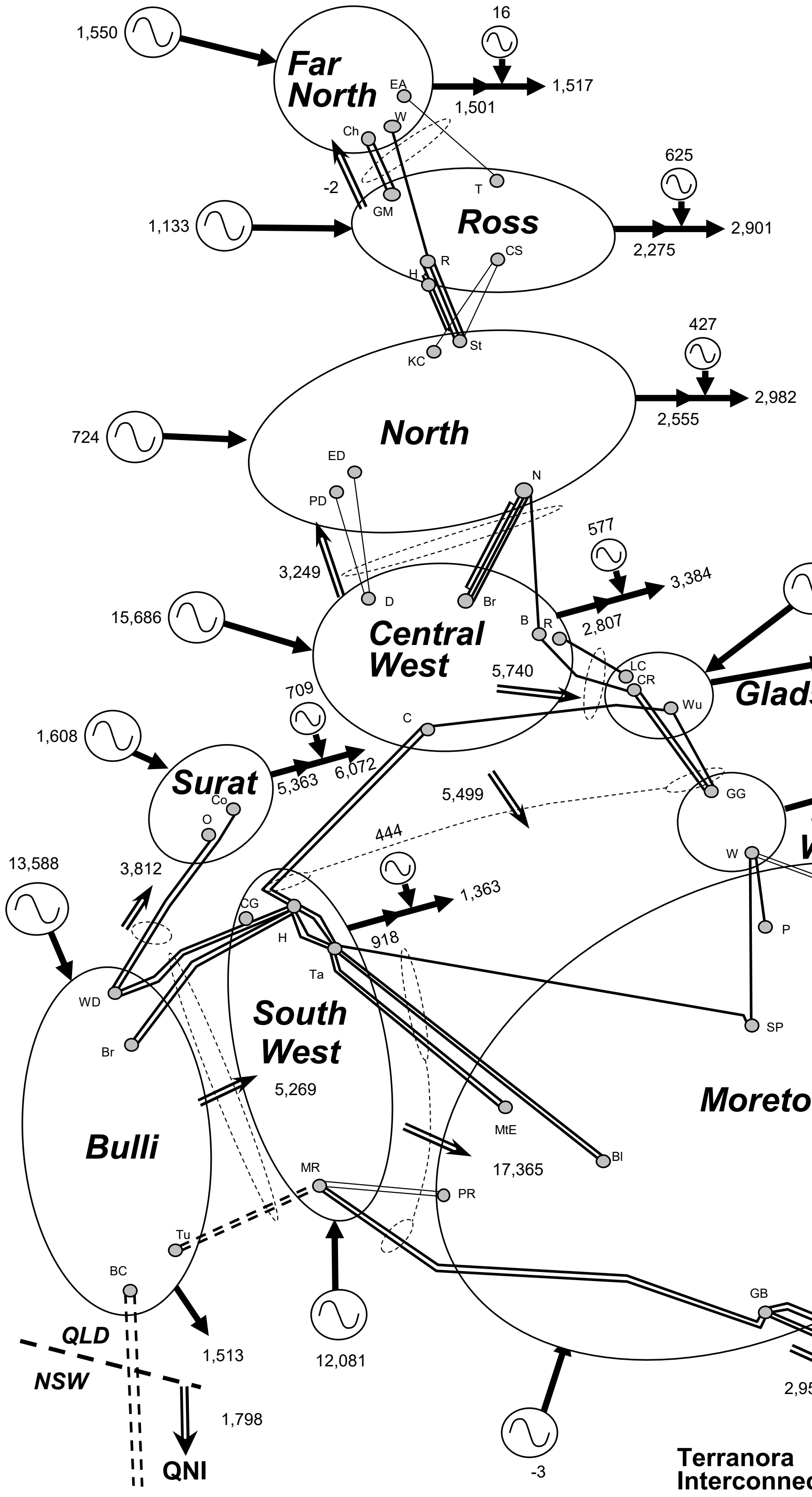


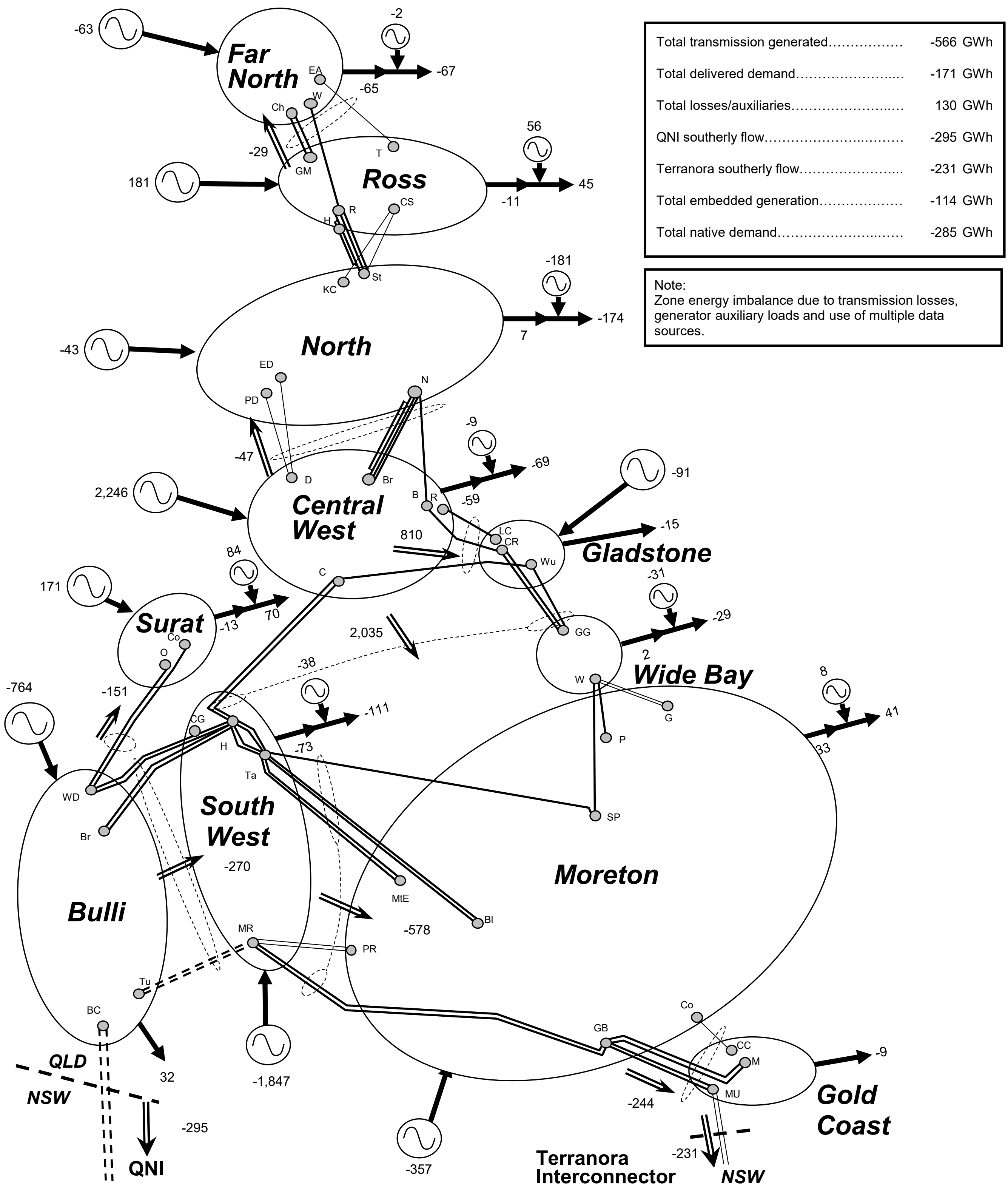
Figure 6.8 2024/25 zonal electricity transfers (GWh)



Total transmission generated	53,744 GWh
Total delivered demand	47,306 GWh
Total losses/auxiliaries	4,571 GWh
QNI southerly flow	1,798 GWh
Terranora southerly flow	69 GWh
Total embedded generation	3,068 GWh
Total native demand	50,374 GWh

Note:
Zone energy imbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

Figure 6.9 Change in zonal electrical energy transfers from 2023/24 to 2024/25 (GWh)



6.6.1 Far North Queensland grid section

The maximum power transfer across the FNQ grid section is set by the voltage stability limit associated with an outage of the Ross to Woree tee Tully South 275kV circuit.

The limit equation in Table H.1 of Appendix H shows that the following variables have a significant effect on transfer capability:

- Far North zone generation
- Far North zone shunt compensation levels.

Local (run of river) hydro-electric and wind generation reduces transfer capability but allows more demand to be securely supported in the Far North zone. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins.

However, the additional load cannot be increased by the same amount of the additional local generation due to the reactive load component and increased reactive losses from the distributed nature of the load. As a result, limiting power transfers are lower with the increased local generation, but a greater load can be supplied.

The FNQ grid section was unconstrained in 2024/25. The historical duration of constrained operation for the FNQ grid section is summarised in Figure 6.10.

Figure 6.10 Historical FNQ grid section constraint times

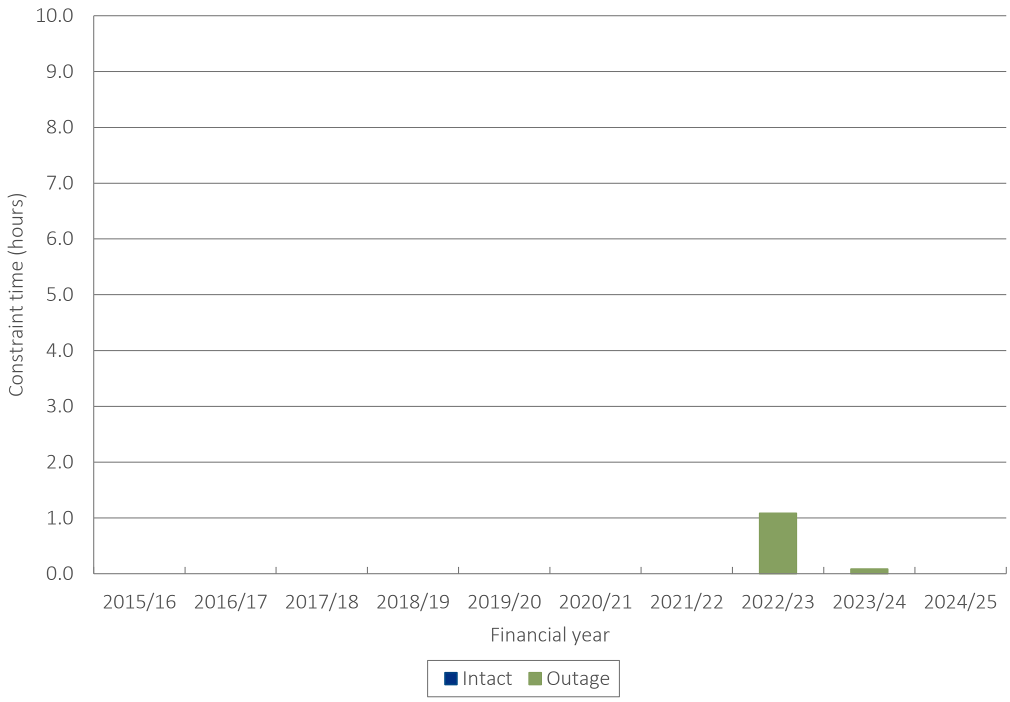
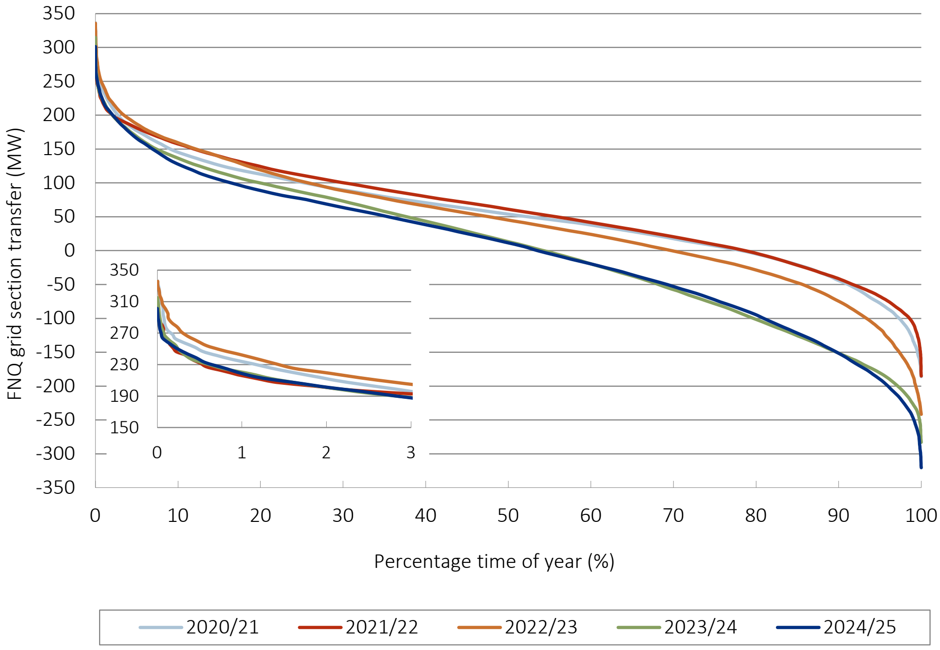


Figure 6.11 provides historical transfer duration curves for the FNQ grid section. The continued increase in generation in the Far North zone has resulted in the zone becoming a net exporter of energy for the first time in 2024/25 (refer to figures 6.7 to 6.9).

Figure 6.11 Historical FNQ grid section transfer duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

6.6.2 Central Queensland to North Queensland grid section

The maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section can be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit. Power transfers may also be constrained by voltage stability limitations associated with the contingency of the Townsville gas turbine or a Stanwell to Broadsound 275kV circuit.

The limit equations in Table H.2 of Appendix H show that the following variables have a significant effect on transfer capability:

- level of Townsville gas turbine generation
- Ross and North zones shunt compensation levels.

The CQ-NQ grid section was unconstrained in 2024/25. The historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 6.12.

Figure 6.12 Historical CQ-NQ grid section constraint times

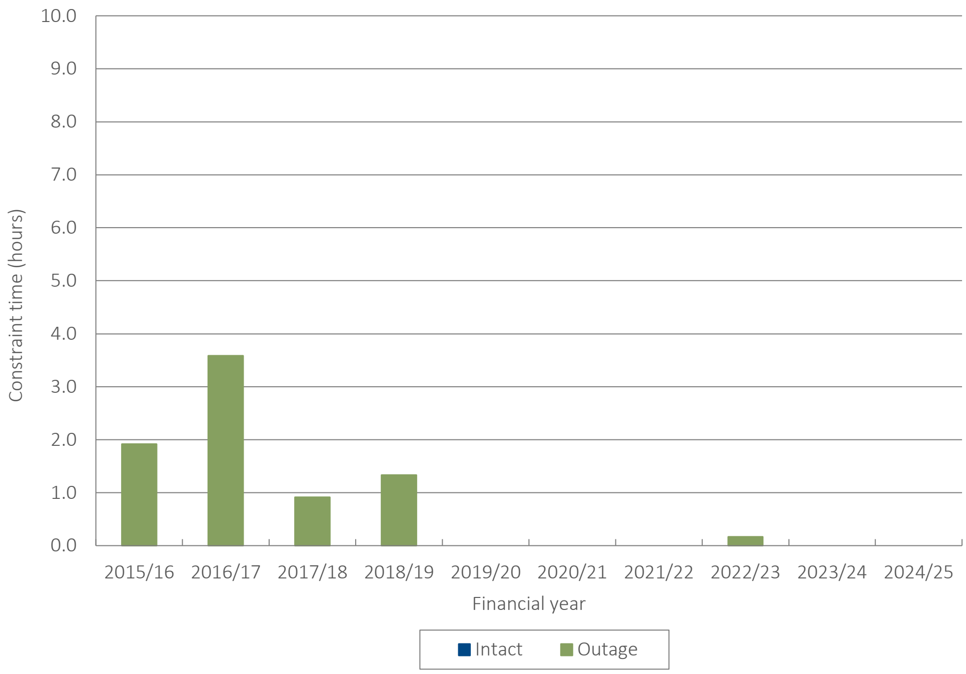
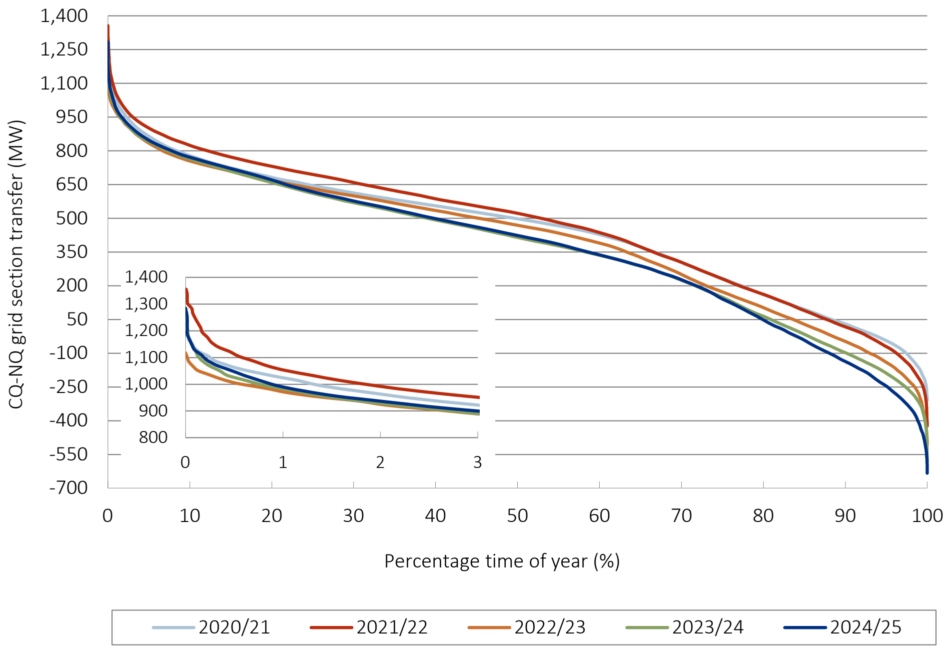


Figure 6.13 provides historical transfer duration curves showing decreases in energy transfer over recent years. This decrease is predominantly attributed to the addition of renewable generation in the Far North, Ross and North zones. Despite reductions in total energy transfer, the peak power transfer in 2024/25 is close to previous years.

Figure 6.13 Historical CQ-NQ grid section transfer duration curves

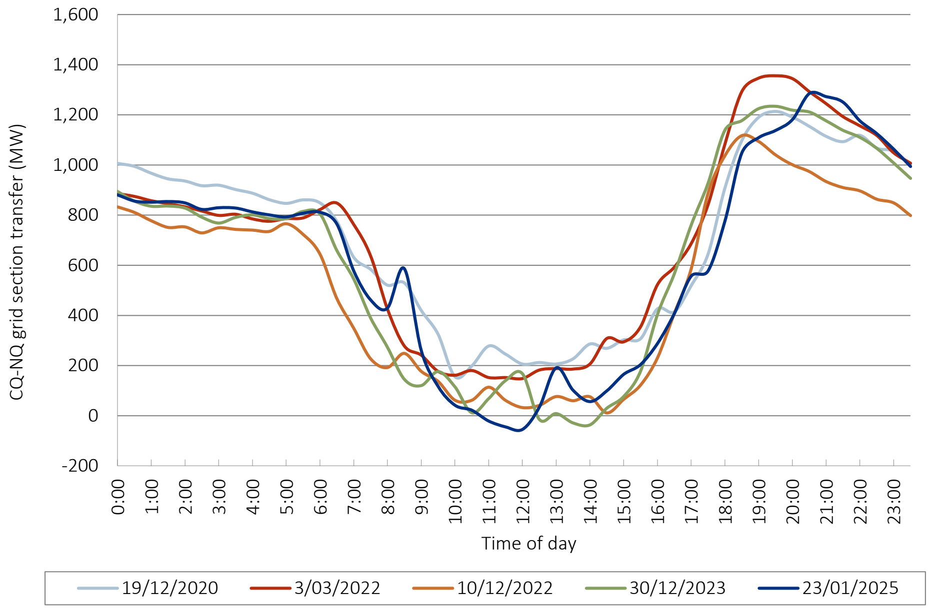


Note:

(1) Inset figure magnifies top of the curve in main figure.

Figure 6.14 provides a different view of the altered power flows experienced over the last five years for the day corresponding to the annual peak CQ-NQ transfer. This shows the impact of solar generation creating minimum demands and network transfers during the middle of the day.

Figure 6.14 Historical CQ-NQ peak grid section transfer daily profile



6.6.3 North Queensland system strength

System strength is typically low in areas with limited synchronous generation, and deteriorates further with high penetration of inverter-based resources (IBR)[10].

Powerlink has determined that the dominant limitation to IBR hosting capacity is the potential for multiple generators, and other transmission connected dynamic plant, to interact in an unstable manner. These dynamic plant control interactions manifest as an unstable or undamped oscillation in the power system voltage. The frequency of the oscillation is dependent on the participating plants but is broadly characterised between 8Hz and 15Hz.

North Queensland's limited synchronous generation and high number of IBR generators, combined with relatively low synchronous fault levels, has made it the focus of system strength limitation in Queensland.

Powerlink has performed Electromagnetic Transient (EMT) analysis to determine the system conditions that could result in unstable operation of IBR plant. The limit equations in Table H.3 of Appendix H reflect the output of this analysis. The limit equations show that the following variables have a significant effect on North Queensland system strength:

- number of synchronous units online in Central and North Queensland
- North Queensland demand
- status of existing synchronous condensers.

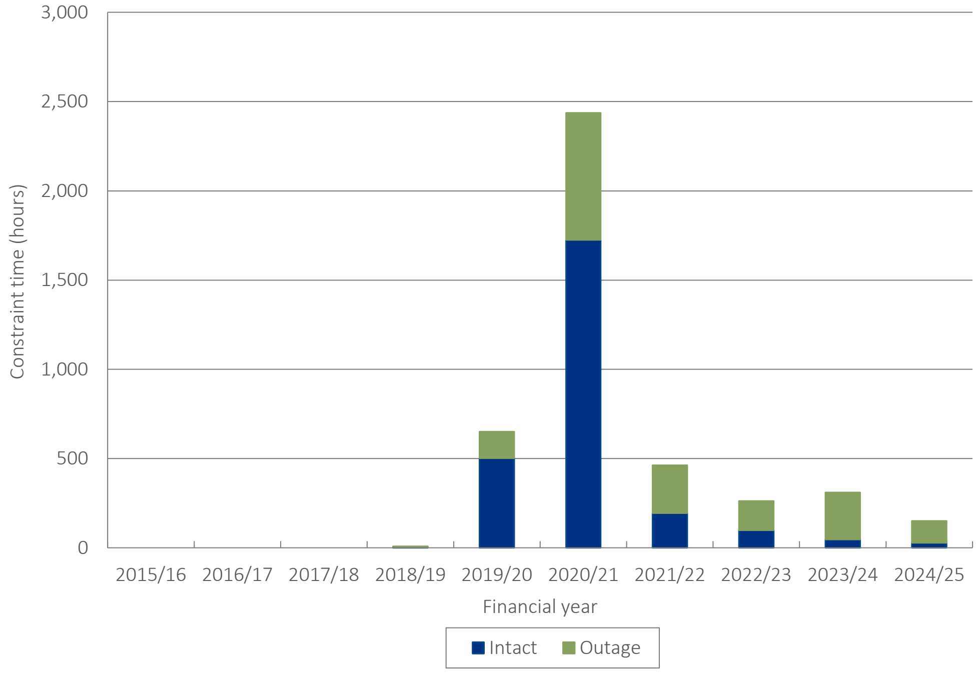
The historical duration of constrained operation for IBR in North Queensland is summarised in Figure 6.15. During 2024/25, IBR in North Queensland experienced 150 hours of constrained operation, of which 123 hours occurred during outage conditions. This is a reduction of approximately 50% compared with the 2023/24 total constraint time.

Powerlink has entered into a System Strength Services Agreement with the owner of the Townsville Power Station to enable modifications to allow the facility to operate in synchronous condenser mode and provide system strength services.

The FNQ System Strength WAMPAC scheme will soon be in service to further reduce the constraint time during outage conditions. This scheme allows IBR to operate at higher levels than were previously allowed when feeders in North Queensland were out of service for maintenance.

10 Refer to Chapter 3 for further discussion of system strength.

Figure 6.15 Historical NQ system strength constraint times



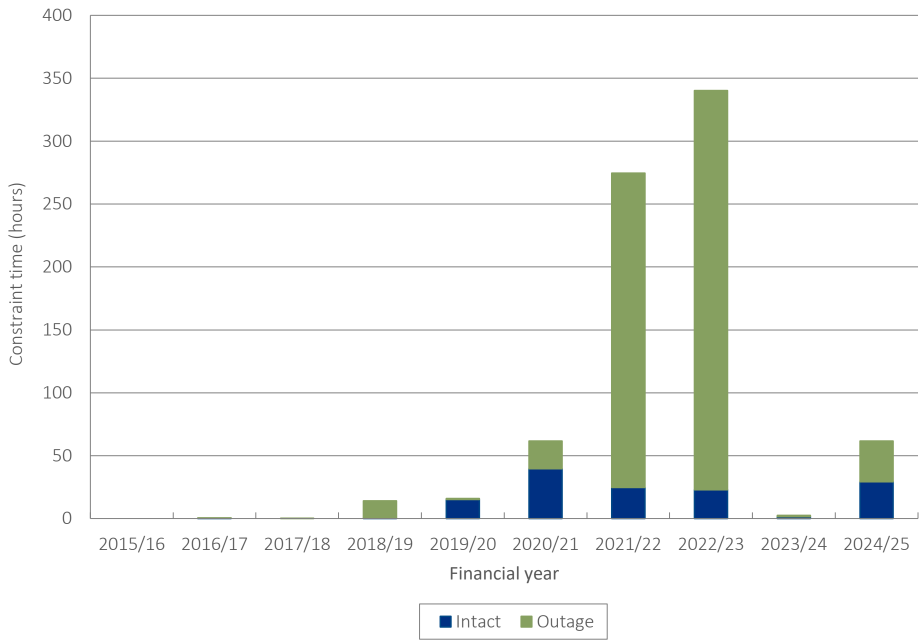
6.6.4 Gladstone grid section

The maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Bouldercombe to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits.

If the rating would otherwise be exceeded following a critical contingency, generation is constrained to reduce power transfers. Powerlink uses dynamic line ratings to assess circuit capacity based on prevailing ambient weather conditions, thereby maximising the available capacity of this grid section and, as a result, reducing market impacts. The appropriate ratings are updated in NEMDE.

The historical duration of constrained operation for the Gladstone grid section is summarised in Figure 6.16. During 2024/25, the Gladstone grid section experienced 54 hours of constrained operation, with approximately half of this time occurring during intact system conditions. These periods of constrained operation coincided with high flows between Central and Southern Queensland.

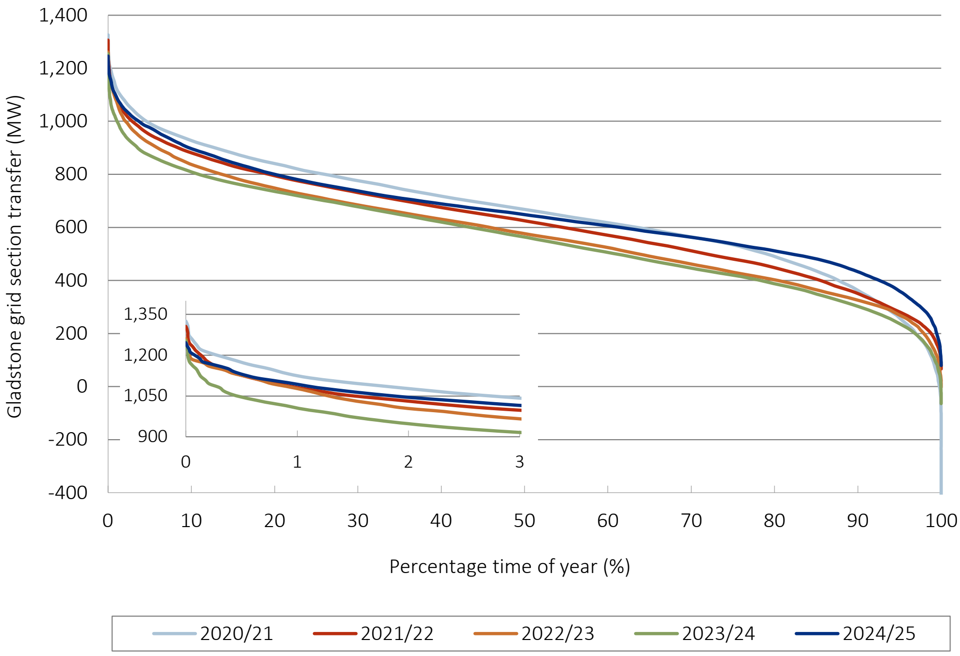
Figure 6.16 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the balance of generation and demand in Gladstone and transfers between Central Queensland and Southern Queensland. Figure 6.17 provides historical transfer duration curves showing higher average utilisation in 2024/25 compared to the previous two years. This increase in flows is due to a slight decrease in generation in the Gladstone zone and increase in flows between Central Queensland and Southern Queensland (refer to figures 6.7 to 6.9).

Powerlink has developed a strategy to increase the capacity of the Gladstone grid section as the generation and demand balance in the Gladstone zone changes (refer to discussion of the Gladstone Project in Section 5.6.2).

Figure 6.17 Historical Gladstone grid section transfer duration curves



6.6.5 Central Queensland to Southern Queensland grid section

The maximum power transfer across the CQ-SQ grid section is set by transient or voltage stability limitations following a Calvale to Halys 275kV circuit contingency.

The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

The limit equation in Table H.4 of Appendix H shows that the following variables have significant effect on transfer capability:

- number of generating units online in the Central West and Gladstone zones
- level of Gladstone Power Station generation.

The historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 6.18. During 2024/25, the CQ-SQ grid section experienced 20 hours of constrained operation, with approximately half of this time occurring during outage conditions. This is considerably less than previous years primarily due to fewer planned outages on these circuits between Gladstone and Moreton zones.

Figure 6.18 Historical CQ-SQ grid section constraint times

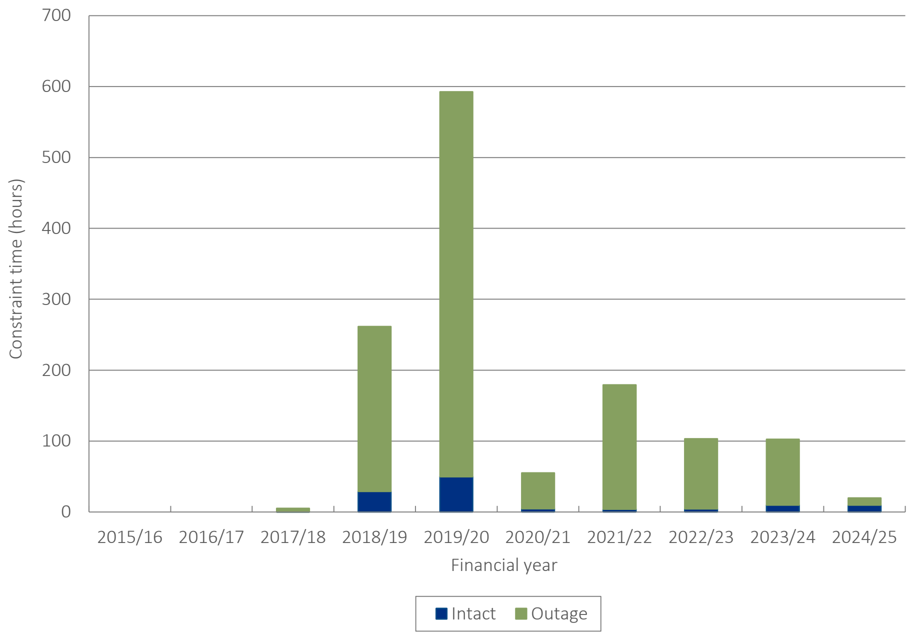
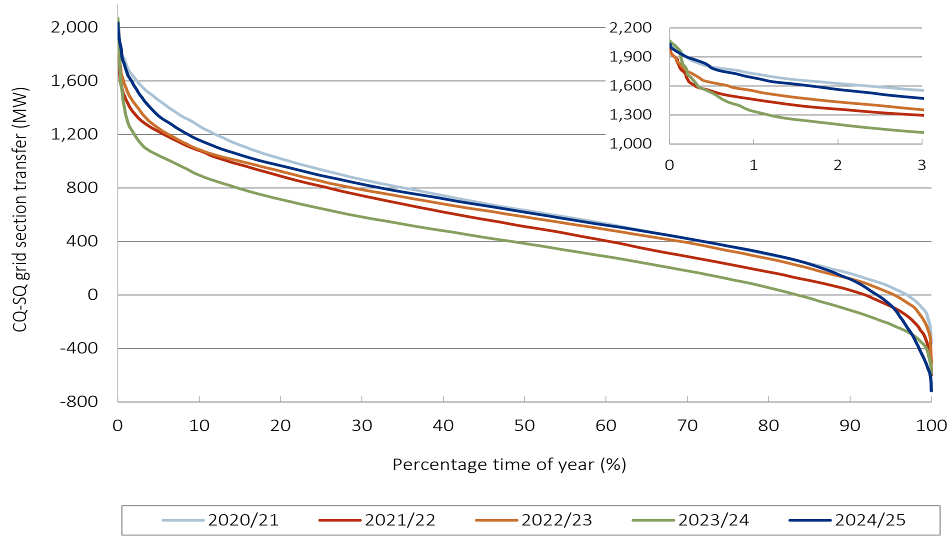


Figure 6.19 provides historical transfer duration curves showing the transfers over the last five years. In the 2024/25 year there was an increase in output from generation in central Queensland largely driven by the return to service of Callide C units. This resulted in the CQ-SQ grid section flows returning to typical historical levels (refer to figures 6.7 to 6.9).

Figure 6.19 Historical CQ-SQ grid section duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

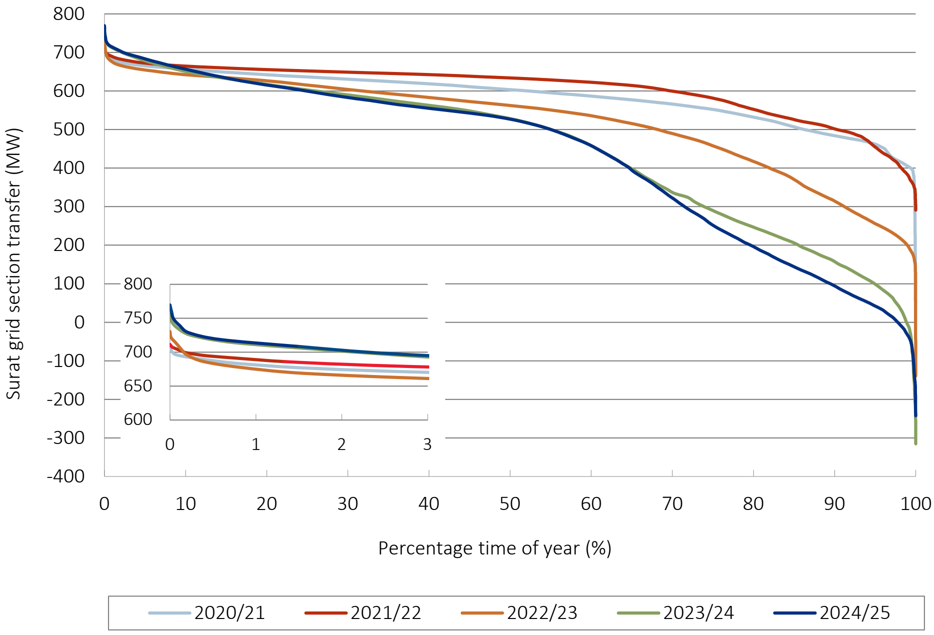
6.6.6 Surat grid section

The maximum power transfer across the Surat grid section is set by the voltage stability associated with insufficient reactive power reserves in the Surat zone following an outage of a Western Downs to Orana 275kV circuit[11]. More generating units online in the zone increases reactive power support and therefore transfer capability. Local generation reduces transfer capability but allows more demand to be securely supported in the Surat zone. There have been no constraints recorded over the history of the Surat grid section.

Figure 6.20 provides the transfer duration curves for the last five years. Energy transfers have reduced in the last year due to the increased output of the solar and wind farms in the Surat zone.

[11] The Orana Substation is connected to one of the Western Downs to Columboola 275kV transmission lines (refer to Figure 6.5).

Figure 6.20 Historical Surat grid section transfer duration curve



Note:

(1) Inset figure magnifies top of the curve in main figure.

6.6.7 South West Queensland grid section

The South West Queensland (SWQ) grid section defines the capability of the transmission network to transfer power from generating stations located in the Bulli zone and northerly flow on QNI to the rest of Queensland. The thermal rating of the Middle Ridge 330/275kV transformer sets maximum power transfer across the SWQ grid section.

The SWQ grid section was unconstrained in 2024/25. The historical duration of constrained operation for the SWQ grid section is summarised in Figure 6.21.

Figure 6.21 Historical South West Queensland grid section constraint times

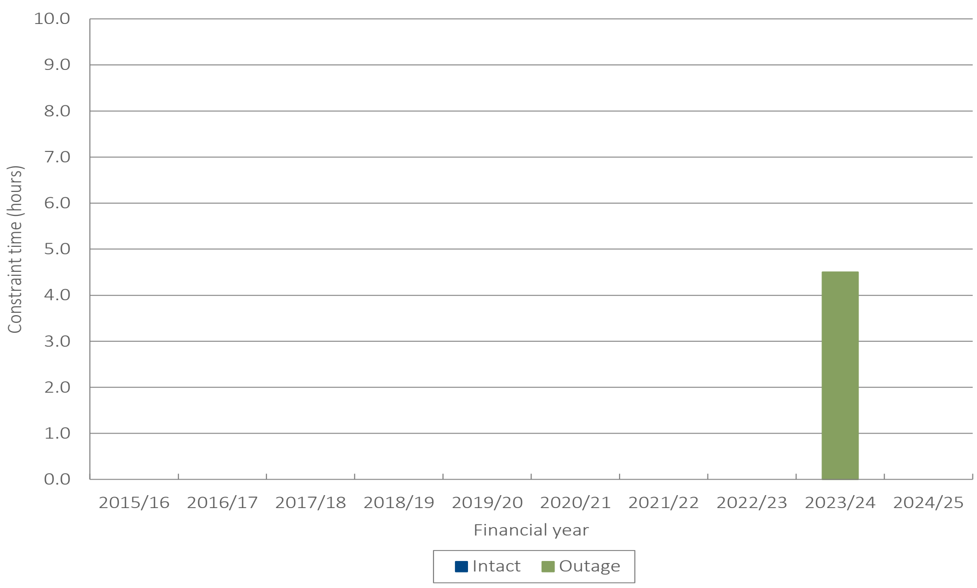
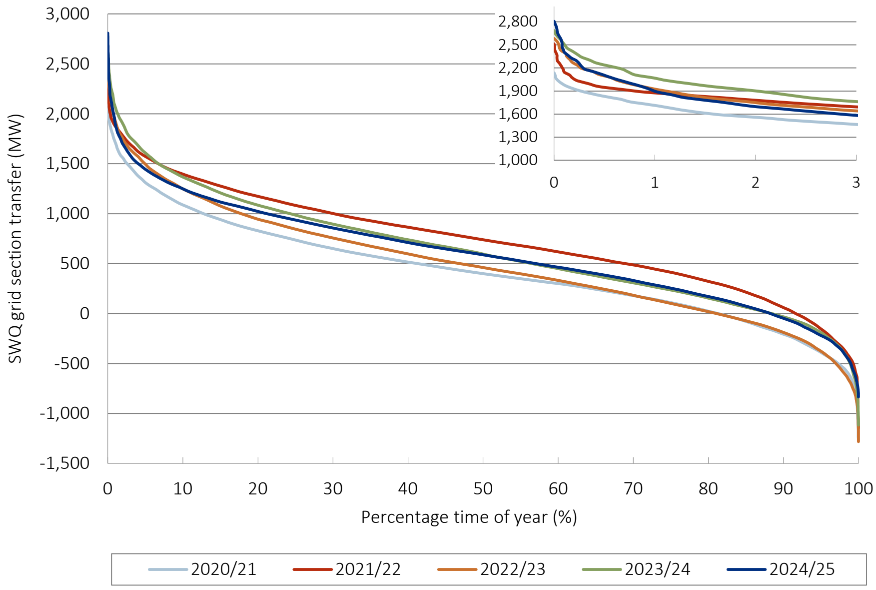


Figure 6.22 provides historical transfer duration curves for the SWQ grid section. Flows in 2024/25 are largely the same as 2023/24 (refer to figures 6.7 to 6.9).

Figure 6.22 Historical SWQ grid section transfer duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

AEMO's 2024 ISP identified the Darling Downs Renewable Energy Zone Expansion as a future ISP project. This project involves an upgrade to the transformer capacity at Middle Ridge Substation. The ISP identified that this increase in capacity would not be required before 2034/35[12] in the Step Change scenario.

6.6.8 Tarong grid section

The maximum power transfer across the Tarong grid section is set by the voltage stability associated with the loss of a Calvale to Halys 275kV circuit or a Tarong to Blackwall 275kV circuit. The limitation arises from insufficient reactive power reserves in Southern Queensland.

Limit equations in Table H.5 of Appendix H show that the following variables have a significant effect on transfer capability:

- QNI transfer and South West and Bulli zones generation
- level of Moreton zone generation
- Moreton and Gold Coast zones capacitive compensation levels.

Any increase in generation west of this grid section, with a corresponding reduction in generation north of the grid section, reduces the CQ-SQ power flow and increases the Tarong limit.

Increasing generation east of the grid section reduces the transfer capability, but increases the overall amount of supportable south-east Queensland demand. The additional load cannot be increased by the same amount of the additional generation east of the grid section due to the reactive load component and increased reactive losses from the distributed nature of the load. As a result, limiting power transfers are lower with the increased local generation, but a greater load can be supplied.

The historical duration of constrained operation for the Tarong grid section is summarised in Figure 6.23. During 2024/25, the Tarong grid section experienced almost 3 hours of constrained operation, mostly during intact system conditions. Most of this constrained operation occurred on a single day with unusual market conditions.

[12] AEMO, 2024 Integrated System Plan, June 2024, page 64.

Figure 6.23 Historical Tarong grid section constraint times

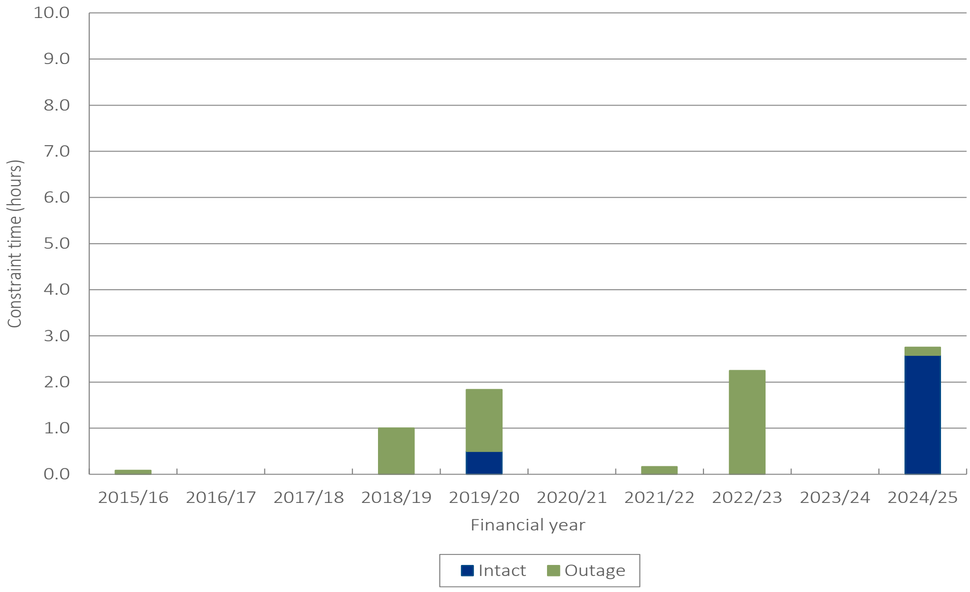
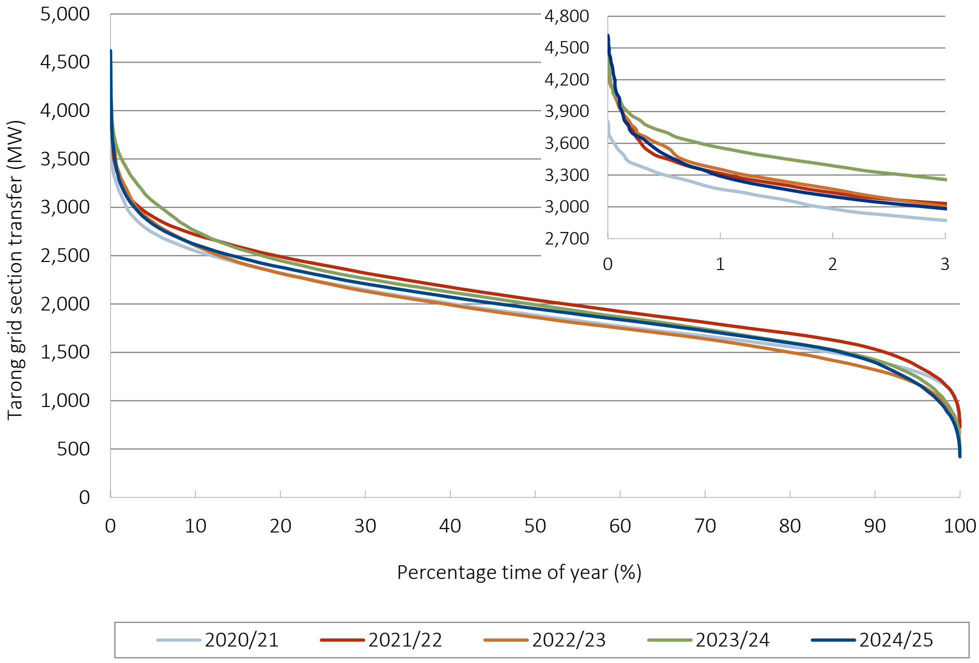


Figure 6.24 provides historical transfer duration curves for the Tarong grid section. There has been a small decrease in Tarong grid section flows this year compared with 2023/24 but they remain similar to historical flows (refer to figures 6.7 to 6.9).

Figure 6.24 Historical Tarong grid section transfer duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

6.6.9 Gold Coast grid section

Maximum power transfer across the Gold Coast grid section is set by voltage stability associated with the loss of a Greenbank to Molendinar 275kV circuit, or a Greenbank to Mudgeeraba 275kV circuit.

The limit equation in Table H.6 of Appendix H shows that the following variables have a significant effect on transfer capability:

- number of generating units online in Moreton zone
- level of Terranora Interconnector transmission line transfer
- Moreton and Gold Coast zones capacitive compensation levels
- Moreton zone to the Gold Coast zone demand ratio.

Reducing southerly flow on Terranora Interconnector reduces transfer capability but increases the overall amount of supportable Gold Coast demand. This is because reactive margins increase with reductions in southerly Terranora Interconnector flow, allowing further load to be delivered before reaching minimum allowable reactive margins. The additional load cannot be increased by the same amount of the reductions in southerly Terranora Interconnector flow due to the reactive load component and increased reactive losses from the distributed nature of the load. As a result, limiting power transfers are lower with reduced Terranora Interconnector southerly transfer, but a greater load can be supplied.

The Gold Coast grid section was unconstrained in 2024/25. The historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 6.25.

Figure 6.25 Historical Gold Coast grid section constraint times

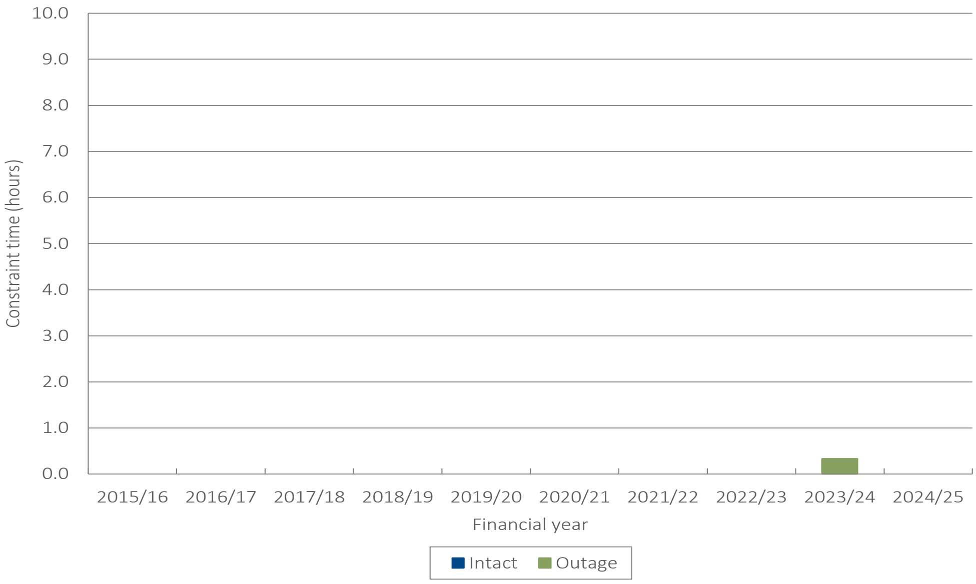
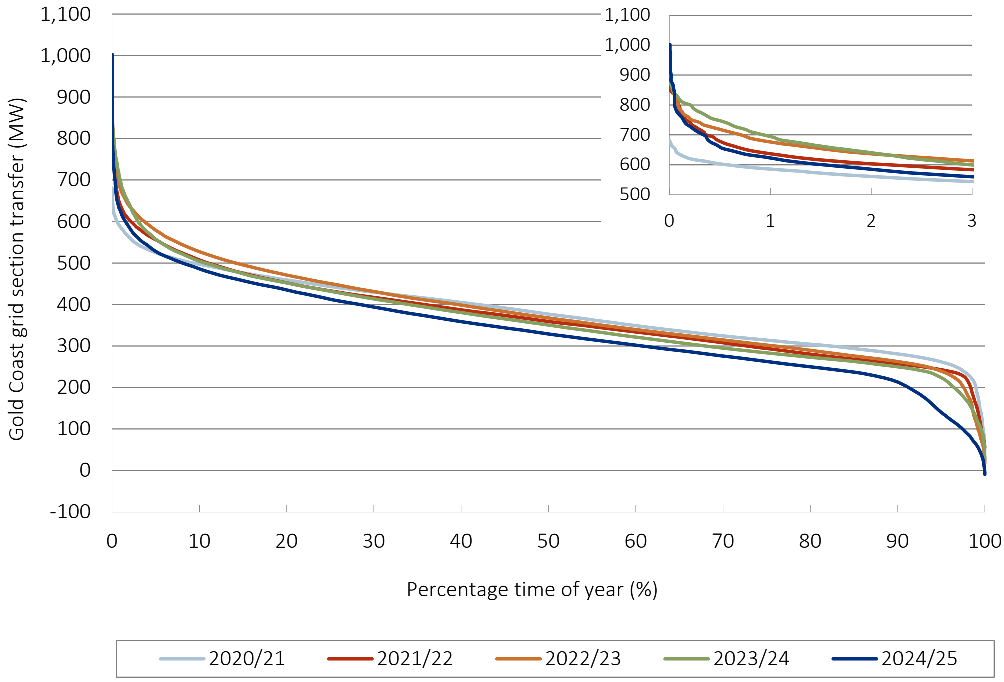


Figure 6.26 provides historical transfer duration curves showing changes in grid section transfer demands and energy are in line with changes in transfer to northern New South Wales (NSW) and changes in Gold Coast loads (refer to figures 6.7 to 6.9). The overall lower flows to the Gold Coast were predominantly the result of lower southerly flows on the Terranora Interconnector.

Figure 6.26 Historical Gold Coast grid section transfer duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

6.6.10 QNI and Terranora Interconnector

The transfer capability across QNI is limited by voltage stability, transient stability, oscillatory stability and thermal rating considerations. The capability across QNI at any time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment and operating conditions of the network.

AEMO publishes Monthly Constraint Reports which include a section examining each of the NEM interconnectors, including QNI and Terranora Interconnector. Information pertaining to the historical duration of constrained operation for QNI and Terranora Interconnector is available in these reports, which can be found on AEMO's website.

For intact system operation, the southerly transfer capability of QNI is most likely to be set by the following:

- voltage stability associated with a fault on the Sapphire to Armidale 330kV transmission line in NSW
- thermal capacity of the 330kV transmission network between Dumaresq and Liddell in NSW.

For intact system operation, the combined northerly transfer capability of QNI and Terranora Interconnector is most likely to be set by the following:

- transient and voltage stability associated with transmission line faults in NSW
- transient and voltage stability associated with loss of the largest generating unit in Queensland
- thermal capacity of the 330kV and 132kV transmission network within northern NSW.

The QNI Minor project is now complete and internetwork testing activities, as required by clause 5.7.7 of the NER, are in the final stages, resulting in increased capacity in both north and south flows.

AEMO's 2024 ISP considered the QNI Connect project that would increase transfer capacity between Queensland and NSW. This project has been deemed an actionable project and Powerlink is working with Transgrid to undertake the Regulatory Investment Test for Transmission (RIT-T) process (refer to Section 7.8)[13].

6.7 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver loads
- historical zonal transmission delivered loads
- intra-zonal system normal constraints
- double circuit transmission lines categorised as vulnerable by AEMO[14]
- Powerlink's management of high voltages associated with light load conditions.

Double circuit transmission lines that experience a lightning trip of all phases of both circuits (where its magnitude or degree is not considered an Exceptional Event[15]) are categorised by AEMO as vulnerable. A double circuit transmission line in the vulnerable list is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected close to the line. A double circuit transmission line will remain on the vulnerable list until it is demonstrated that the asset characteristics have been improved to make the likelihood of a double circuit lightning trip no longer reasonably likely to occur or until the Lightning Trip Time Window (LTTW) expires from the last double circuit lightning trip. The LTTW is three years for a single double circuit trip event or five years where multiple double circuit trip events have occurred during the LTTW.

Statewide delivered energy has reduced slightly from 2023/24 to 2024/25. However, many zones observed a widening of the demand spread with either record maximum demand or record minimum demand (both in some cases). This is a trend that has continued from recent years driven by the growth of rooftop solar PV. As at 30 June 2025 there was approximately 7,200MW of rooftop solar PV generating capacity in the state, an increase of 806MW over the year[16].

This year saw a return to service of the Callide C4 unit which resulted in a large increase in energy generation in the Central West zone. There was a corresponding drop in energy generation in the Bulli and South West zones (refer to figures 6.7 to 6.9).

The following sections show load duration curves for each zone[17].

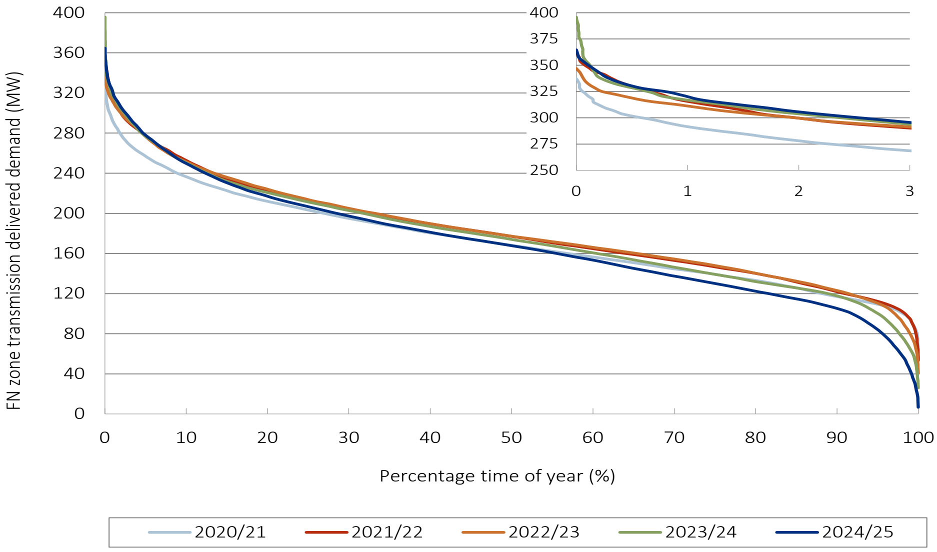
13 AEMO, 2024 Integrated System Plan, June 2024, page 63. The ISP states the Project Assessment Draft Report for the project is due by 25 June 2026.
14 AEMO, List of Vulnerable Transmission Lines, effective April 2025.
15 An Exceptional Event is defined in AEMO's Power System Security Guidelines (SO_OP_3715) as a simultaneous trip of a double circuit transmission line during a lightning storm caused by an event that is far beyond what is usual in magnitude or degree for what could be reasonably expected to occur during a lightning storm.
16 Clean Energy Regulator, Small-scale Installation Postcode Data.
17 Refer to figures 2.17 to 2.19 for annual transmission delivered demand load duration curves for the Queensland region as a whole.

6.7.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2024/25. The zone includes the non-scheduled embedded generator, Lakeland Solar and Storage[18], which provided 16GWh during 2024/25.

Figure 6.27 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has reduced by 4.1% between 2023/24 and 2024/25. The maximum transmission delivered demand in the zone was 365MW, lower than the record set the previous year. The minimum transmission delivered demand in the zone was 7MW, which is the lowest minimum demand on record.

Figure 6.27 Historical Far North zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the Far North zone in the vulnerable list:

- Chalumbin to Turkinje 132kV double circuit transmission line, which tripped in November 2022 and again in January 2025
- Ross to Woree tee Tully South 275kV circuit and Cardwell to Tully 132kV circuit, last tripped in February 2024. These lines share the same transmission towers
- Kamerunga to Barron Gorge Power Station 132kV double circuit transmission line, last tripped in December 2024.

6.7.2 Ross zone

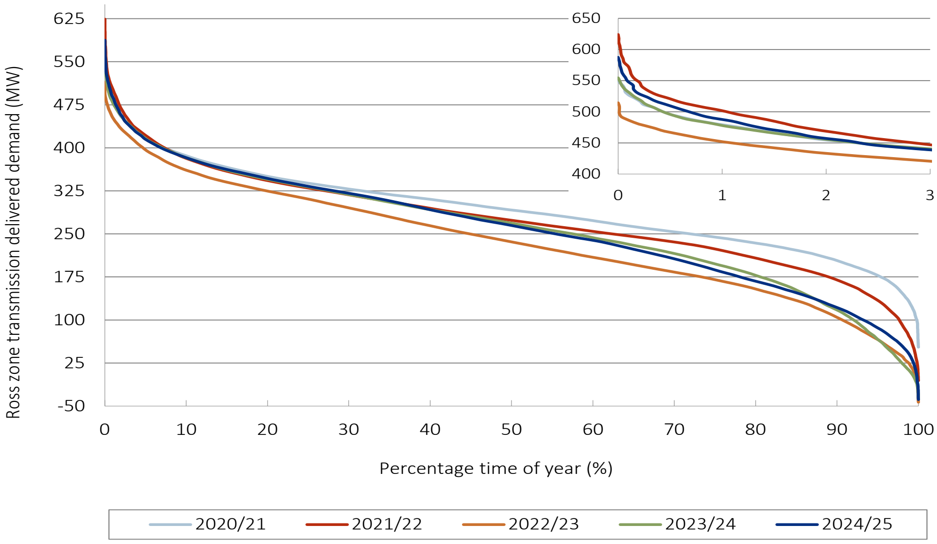
The Ross zone experienced no load loss for a single network element outage during 2024/25.

The Ross zone includes several embedded generators: the scheduled 66kV steam turbine component of the Townsville Power Station (part of a closed-cycle gas turbine system); the semi-scheduled, distribution-connected Kidston Solar Farm, Kennedy Energy Park, and Sun Metals Solar Farm (direct connected); and significant non-scheduled generators such as Hughenden Solar Farm and Pioneer Mill[19]. These embedded generators provided 625GWh during 2024/25.

Figure 6.28 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 0.5% between 2023/24 and 2024/25. Native load in the zone increased but this was offset by the increase in embedded generation. The peak transmission delivered demand in the zone was 587MW, which is lower than the maximum demand over the last five years of 624MW set in 2021/22. The minimum transmission delivered demand in the zone was 39MW, which is the slightly higher than the record minimum set in 2022/23.

18 Refer to Figure 2.10 for load measurement definitions.
19 Refer to Figure 2.10 for load measurement definitions.

Figure 6.28 Historical Ross zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the Ross zone in the vulnerable list:

- Ross to Chalumbin 275kV double circuit transmission line. This double circuit tripped due to lightning in January 2020 and again in November 2022
- Ross to Townsville South 132kV double circuit transmission line, last tripped in April 2025.

6.7.3 North zone

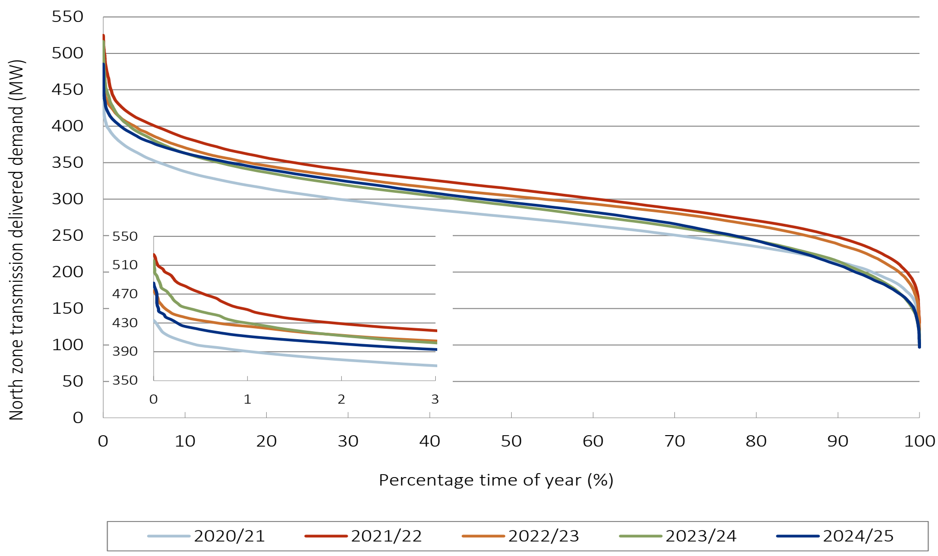
The North zone experienced a single load loss event for a single network element outage during 2024/25. The outage lasted approximately 7 hours, resulting in 27MWh of lost energy. The loads impacted by the outage are supplied by a single radial connection under intact system conditions.

The North zone includes semi-scheduled embedded generator Collinsville Solar Farm and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill[20]. These generators provided 427GWh during 2024/25.

Figure 6.29 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has increased by 0.3% between 2023/24 and 2024/25. The peak transmission delivered demand reached 485MW, which is lower than maximum demand over the last five years of 525MW set in 2021/22. The minimum transmission delivered demand in the zone was 97MW, which is the lowest minimum demand in the last five years.

[20] Refer to Figure 2.10 for load measurement definitions.

Figure 6.29 Historical North zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the North zone in the vulnerable list:

- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 2023
- Collinsville North to Stony Creek and Collinsville North to Newlands lines, last tripped November 2022
- Strathmore to Clare South and Strathmore to Clare South tee King Creek 132kV double circuit transmission line, last tripped December 2023.

6.7.4 Central West zone

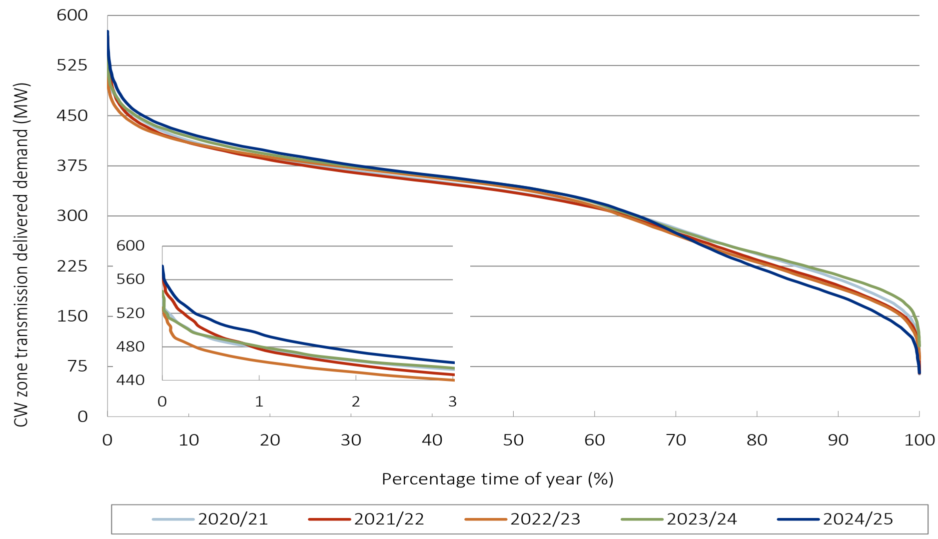
The Central West zone experienced no load loss for a single network element outage during 2024/25.

The Central West zone includes the scheduled embedded Barcaldine generator, semi-scheduled embedded generators Clermont, Emerald and Middlemount solar farms, and significant non-scheduled embedded generators Barcaldine and Longreach solar farms, German Creek and Oaky Creek[21]. These generators provided 577GWh during 2024/25.

Figure 6.30 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 2.1% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 576MW, which is the highest maximum demand over the last five years. The minimum transmission delivered demand in the zone was 66MW, which is close to the record minimum demand recorded in 2020/21.

21 Refer to Figure 2.10 for load measurement definitions.

Figure 6.30 Historical Central West zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the Central West zone in AEMO's lightning vulnerable transmission line.

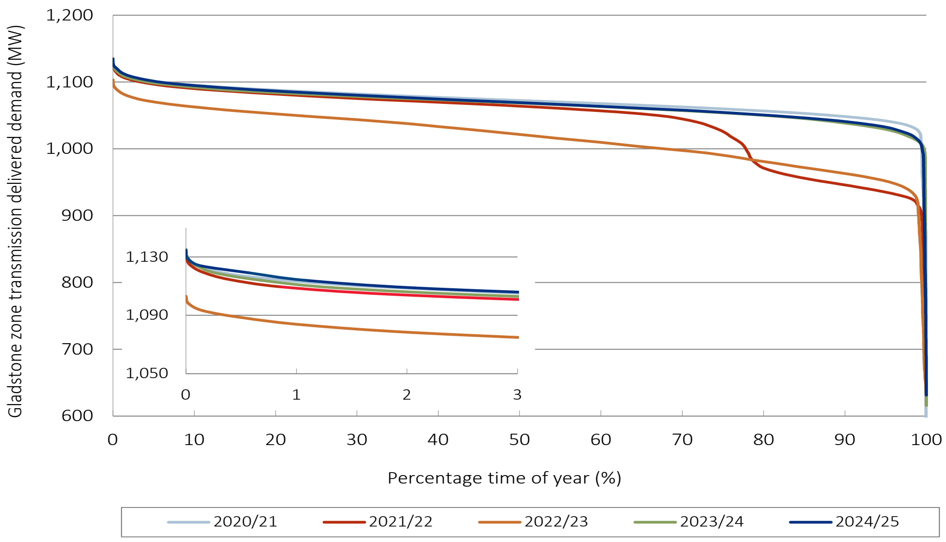
6.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2024/25.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators[22].

Figure 6.31 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has reduced by 0.2% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 1,135MW, which is equal to the highest maximum demand over the last five years. Minimum demand coincides with short periods when one or more potlines at Boyne Smelters Limited (BSL) are out of service. The minimum transmission delivered demand in the zone was 631MW.

Figure 6.31 Historical Gladstone zone transmission delivered load duration curves



Note:

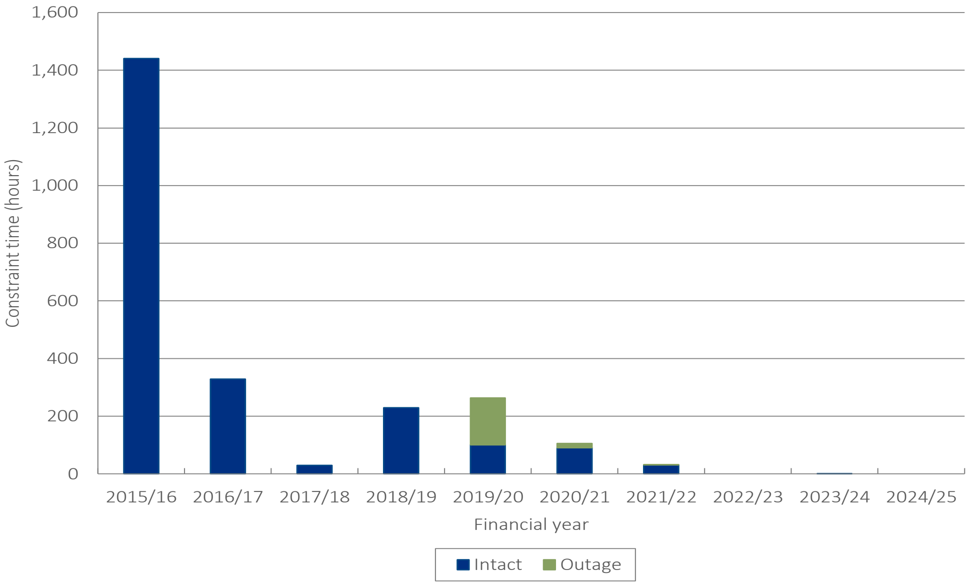
(1) Inset figure magnifies top of the curve in main figure.

[22] Refer to Figure 2.10 for load measurement definitions.

Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing at BSL's substation. The constraint limits generation from Gladstone Power Station, mainly from the units connected at 132kV. AEMO identifies the system intact constraint by constraint identifier Q>NIL_BI_FB. This constraint was implemented in AEMO's market system from September 2011.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 6.32. During 2024/25, the feeder bushing constraint did not constrain network dispatch at any time.

Figure 6.32 Historical Boyne Island feeder bushing constraint times



There are currently no double circuits in the Gladstone zone in AEMO's lightning vulnerable transmission line list.

6.7.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2024/25.

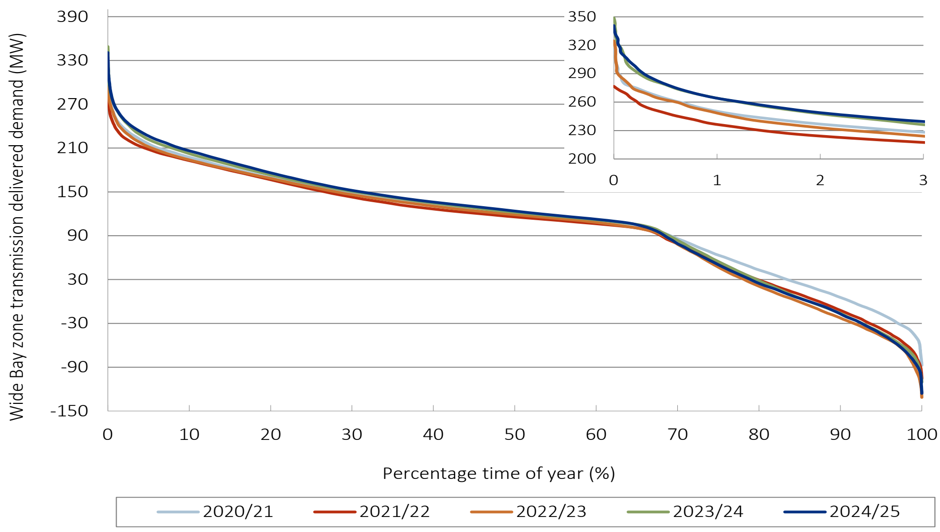
The Wide Bay zone includes the semi-scheduled embedded generators, Childers and Susan River Solar Farms, and a significant non-scheduled embedded generator in the Isis Central Sugar Mill[23]. These generators provided 199GWh during 2024/25.

Figure 6.33 provides historical transmission delivered load duration curves for the Wide Bay zone. The Wide Bay zone is one of three zones in Queensland where the delivered demand reaches negative values, meaning that, at times, the embedded generation exceeds the native load. The transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to supply loads in other zones.

While energy has seen significant reductions in recent years, the energy delivered from the transmission network increased by 0.2% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 341MW, which is slightly lower than the record maximum demand set in 2023/24. The minimum transmission delivered demand in the zone was -126MW, which is slightly higher than the record minimum demand of -131MW recorded in 2022/23.

[23] Refer to Figure 2.10 for load measurement definitions.

Figure 6.33 Historical Wide Bay zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the Wide Bay zone in AEMO's lightning vulnerable transmission line list.

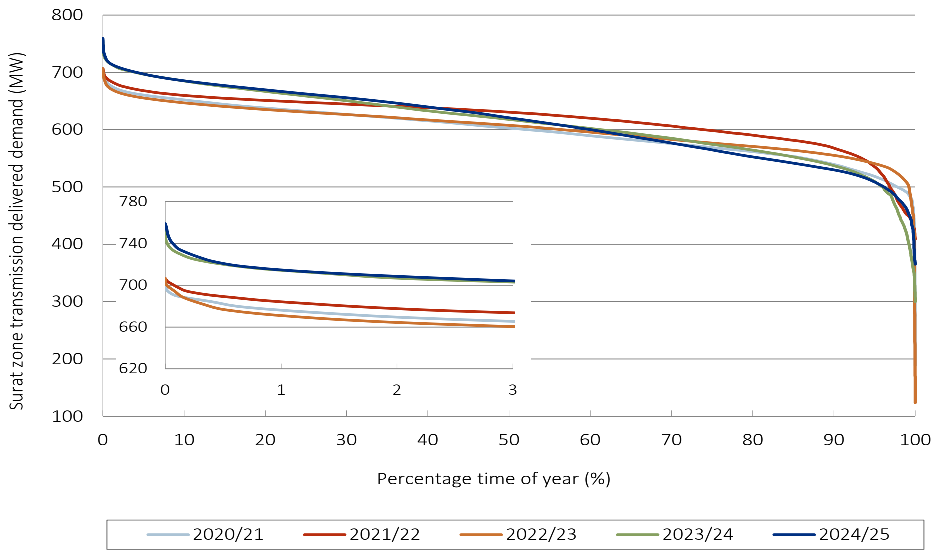
6.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2024/25.

The Surat zone includes the scheduled embedded Roma generator, the direct connected embedded Condamine generators, the semi-scheduled Dulacca Wind Farm and the significant non-scheduled embedded generator Baking Board Solar Farm[24]. These generators supplied 709GWh during 2024/25.

Figure 6.34 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has reduced by 0.2% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 759MW, which is a record maximum demand for the zone. The minimum transmission delivered demand in the zone was 365MW which is typical for this zone.

Figure 6.34 Historical Surat zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the Surat zone in AEMO's lightning vulnerable transmission line list.

[24] Refer to Figure 2.10 for load measurement definitions.

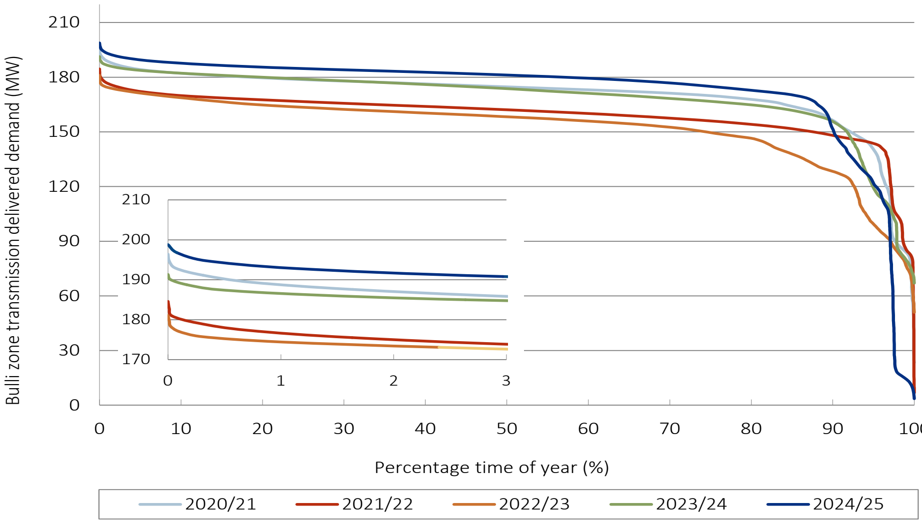
6.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2024/25.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators[25].

Figure 6.35 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by 2.1% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 199MW which is lower than the maximum demand of 210MW set in 2019/20. The minimum transmission delivered demand in the zone was 4MW, which is the lowest demand on record.

Figure 6.35 Historical Bulli zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the Bulli zone in AEMO's lightning vulnerable transmission line list.

6.7.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2024/25.

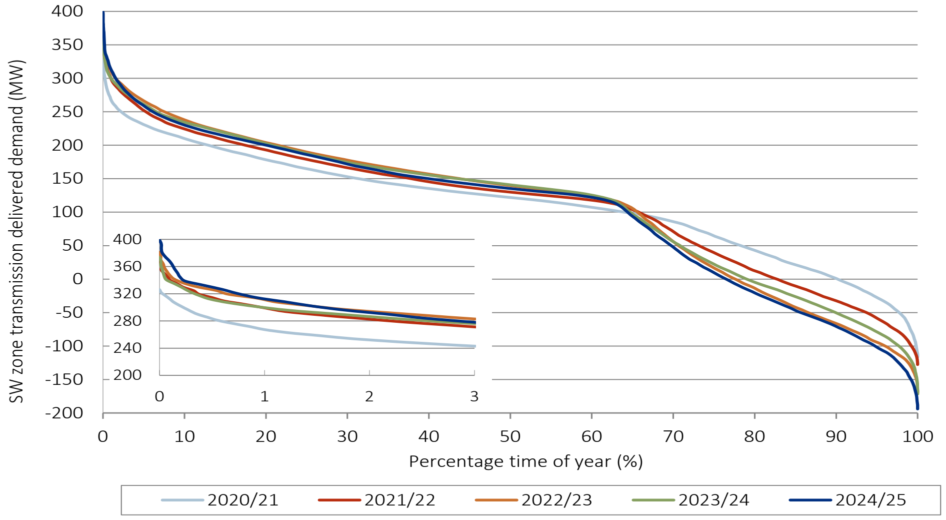
The South West zone includes the semi-scheduled embedded generators Kingaroy, Oakey 1, Oakey 2, Yarranlea, Maryrorough, and Warwick Solar Farms[26]. These generators provided 444GWh during 2024/25.

Figure 6.36 provides historical transmission delivered load duration curves for the South West zone. The South West zone is one of three zones in Queensland where the delivered demand reaches negative values, meaning that the embedded generation exceeds the native load. The transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to supply loads in other zones.

Energy delivered from the transmission network has reduced by 7.3% between 2023/24 and 2024/25, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 399MW, a new record maximum demand. The minimum transmission delivered demand in the zone was -194MW, which is the lowest demand on record. A new minimum demand record has been set in this zone every year for the past seven years.

25 Refer to Figure 2.10 for load measurement definitions.
26 Refer to Figure 2.10 for load measurement definitions.

Figure 6.36 Historical South West zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the South West zone in AEMO's lightning vulnerable transmission line list.

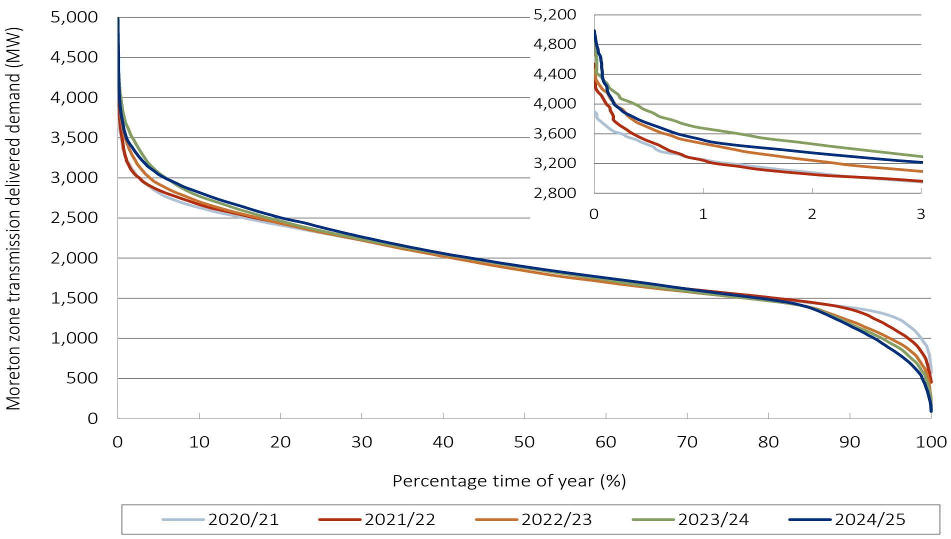
6.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2024/25.

The Moreton zone includes the significant non-scheduled embedded generators Sunshine Coast Solar Farm, Bromelton and Rocky Point[27]. These generators provided 70GWh during 2024/25.

Figure 6.37 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network increased by 0.2% between 2023/24 and 2024/25. The peak transmission delivered demand in the zone was 4,989MW, which is highest maximum demand on record. The minimum transmission delivered demand in the zone was 89MW, which is the lowest demand on record.

Figure 6.37 Historical Moreton zone transmission delivered load duration curves



Note:

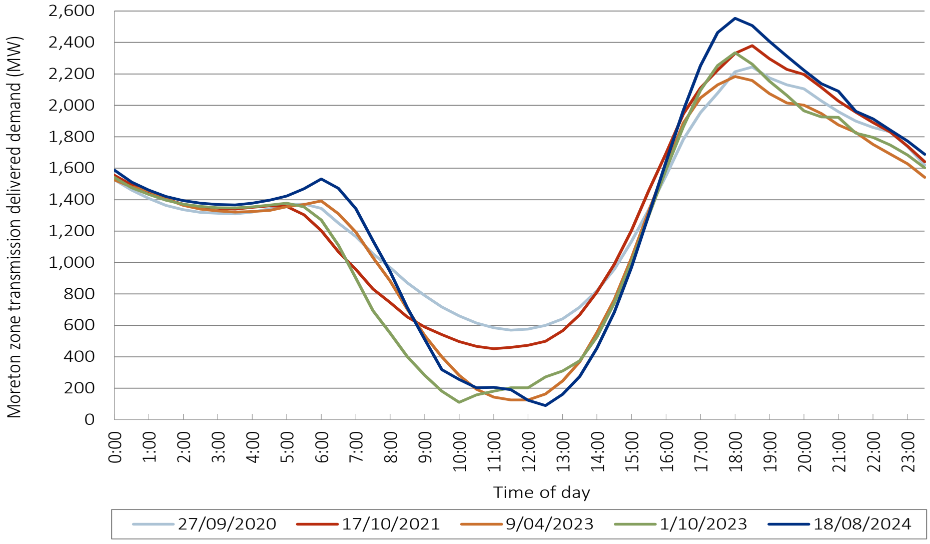
(1) Inset figure magnifies top of the curve in main figure.

High voltages associated with these light load conditions are currently managed with existing reactive sources. However, voltage control within Powerlink's and Energex's network is forecast to become increasingly challenging for longer durations. In October 2024, a bus reactor was commissioned at Belmont Substation to address the long-term reactive requirements.

[27] Refer to Figure 2.10 for load measurement definitions.

Figure 6.38 provides the daily load profile for the minimum transmission delivered days for the Moreton zone over the last five years. This figure shows that the difference between the minimum demand and maximum demand on these days is increasing in magnitude. This is resulting in operational challenges to manage the network during periods of rapidly increasing demand.

Figure 6.38 Historical Moreton zone minimum transmission delivered daily profile



There are currently no double circuits in the Moreton zone in AEMO's lightning vulnerable transmission line list.

6.7.11 Gold Coast zone

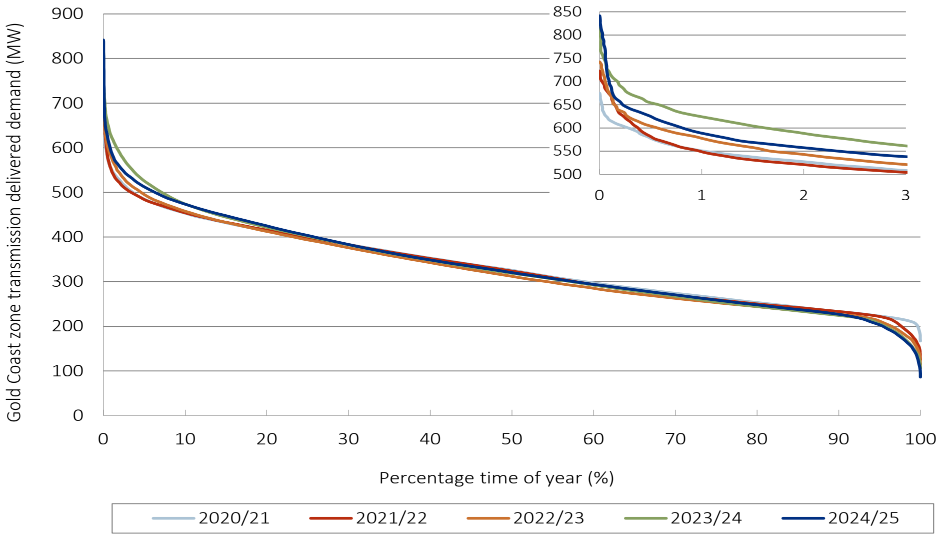
The Gold Coast zone experienced no load loss for a single network element outage during 2024/25.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators[28].

Figure 6.39 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network reduced by 0.3% between 2023/24 and 2024/5. The peak transmission delivered demand in the zone was 842MW, which is the highest maximum demand on record. The minimum transmission delivered demand in the zone was 86MW which is the lowest demand on record.

28 Refer to Figure 2.10 for load measurement definitions.

Figure 6.39 Historical Gold Coast zone transmission delivered load duration curves



Note:

(1) Inset figure magnifies top of the curve in main figure.

There are currently no double circuits in the Gold Coast zone in AEMO's lightning vulnerable transmission line list.

Strategic projects

07

This chapter explores possible new loads within the resource-rich areas of Queensland and the associated coastal port facilities, as well as the potential future electrification of mining and industrial processing loads that may cause network limitations to emerge within the 10-year outlook period. In addition, the chapter outlines potential upgrades to major grid sections that support Queensland's energy future.

Key highlights

- Powerlink is aware of multiple proposals for large mining, metal processing and other industrial loads, as well as the electrification of existing loads. These developments could impact the performance and adequacy of the transmission system within the 10-year outlook period.
- On 10 October 2025, the Queensland Government released its Energy Roadmap. Central to the Energy Roadmap is a commitment to leverage existing assets and opportunities to rebuild aging assets with higher capacity 275 kilovolt (kV) infrastructure.
- In response to moderating load forecasts and the current cost of transmission network delivery, Powerlink is undertaking a staged, flexible network development approach to unlock new generation connection opportunities across Queensland.
- Powerlink's approach to investment planning and timing is driven on a principle of prudent investment and innovation to prepare Queensland's network for the opportunities and challenges ahead. This approach enables timely responses to market signals, supports generation growth and integrates a mix of firming assets such as batteries, gas-powered generation and longer duration solutions like Pumped Hydro Energy Storage (PHES).

7.1 Introduction

On 10 October 2025, the Queensland Government released its Energy Roadmap—a strategic plan to deliver an affordable, reliable and sustainable energy future. The Energy Roadmap commits to leveraging existing assets, optimising investments, and enabling new generation through targeted transmission upgrades. Importantly, it highlights Queensland's commitment to the Priority Transmission Investment (PTI) framework and Regional Energy Hubs to progress critical transmission infrastructure efficiently and effectively[1].

In line with the Energy Roadmap, Powerlink is implementing a staged development model that is prudent and efficient, providing flexibility to accommodate future load growth and generation patterns. This approach focuses on:

- targeted 275kV augmentations and asset rebuilds to relieve congestion and better utilise existing infrastructure
- rebuilding aging assets with higher capacity solutions to provide flexibility for future load growth and generation patterns
- applying staged development principles to respond efficiently to market signals and integrate firming technologies such as PHES.

Within this strategic context, Powerlink is aware of several proposals for large mining, metal processing, other industrial loads, including the electrification of existing operations. While these developments have not progressed sufficiently to be included (either wholly or in part) in Powerlink's Central scenario forecast of future load, they collectively represent approximately 2,982 megawatts (MW) across northern, central and southern Queensland, as outlined in Table 2.1. Their potential impact on transmission system performance and adequacy is explored in Section 7.2, considering:

- existing and committed network and generation infrastructure (refer to tables 6.1 and 6.2)
- the potential development of new generation areas and future projects that may be required within the 10-year outlook period.

Powerlink's network development approach also reflects evolving market conditions and policy changes, including:

- moderated demand forecasts, particularly for hydrogen loads in central Queensland
- escalating transmission costs, making large-scale backbone builds less economically viable[2]
- cancellation of the Pioneer-Burdekin PHES in November 2024
- operating timeframes of coal-fired power stations owned by the Queensland Government.

These factors reinforce the need for a flexible, staged approach rather than large-scale backbone expansion.

1 Queensland Government, Energy Roadmap, October 2025.
2 For further discussion on cost escalation for transmission projects and equipment, see Powerlink, Powerlink 2027-32 Revenue Proposal (Draft), September 2025, pages 11-15.

In September 2025, Powerlink published a Draft Revenue Proposal for the 2027-32 regulatory period. The proposal considered contingent projects for the regulatory period to respond to increased local demand and/or reduced generation, and potential future actionable projects under the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP). As indicated in the proposal, should any contingent project triggers occur, Powerlink will undertake the required regulatory processes, including public consultation and a request for non-network solutions[3]. Where relevant, potential network solutions for strategic projects that are aligned to a contingent project in the Draft Revenue Proposal are noted in this chapter.

While this chapter presents potential network options, Powerlink will also assess non-network solutions as part of our evaluation process to ensure all technically and economically viable approaches are considered.

7.2 Network options to meet reliability obligations for potential new loads

If network limitations emerge from possible yet uncertain loads, Powerlink will leverage targeted transmission augmentations that are consistent with the Queensland Government's Energy Roadmap. These will be considered holistically with any emerging condition-based drivers as part of the longer-term planning process, and in conjunction with the ISP.

To help meet customer timeframes, Powerlink may implement bridge solutions that preserve reliability and future optionality. These could include non-firm access arrangements supported by special protection schemes so proponents can progress projects, as well as advancing preparatory activities to reduce delivery lead times as project commitments become more certain.

Details of potential network options are outlined in sections 7.2.1 to 7.2.4 for the transmission grid sections that could be impacted by the commitment of potential new large loads that are excluded from the Low and Central scenario forecast (refer to Table 2.1).

7.2.1 CopperString

The Energy Roadmap confirms that Queensland Investment Corporation (QIC) will deliver the Eastern Link (Townsville to Hughenden) of CopperString with major construction commencing by 2028 and commercial operations by 2032 (subject to approvals). QIC is also beginning the work to deliver the Western Link (Hughenden to Mount Isa).

The Eastern Link will be constructed at 330kV and is expected to connect to a new Powerlink switching station at Reid River, by cutting into the existing 275kV network between Strathmore and Ross substations. In the immediate term, the $200 million North West Energy Fund will support local generation and storage solutions - in partnership with the private sector - across Mount Isa, Cloncurry, Julia Creek and Richmond.

The Energy Roadmap notes that the Eastern Link will enable the connection of new generation in the Flinders region. The hosting capacity for new generation within this region, together with further generation development in northern Queensland, has the potential to significantly increase power transfers from northern to central Queensland.

This increased transfer may prompt the need to assess whether targeted network enhancements efficiently support reliable energy delivery and realise net market benefits for customers.

7.2.2 Northern Bowen Basin coal mining area

There is strong interest from customers regarding the potential electrification of existing mining operations in the Northern Bowen Basin. Electrification would involve replacing diesel fuel with electricity, and could significantly increase electrical demand and drive substantial requirements for new generation. Rather than being behind the meter, investment in new generation is likely to occur through power purchase agreements (PPAs) with large-scale energy suppliers.

Electrifying existing mining processes could see load increase of up to 600MW. This would cause significant voltage and thermal limitations on the existing 132kV transmission system supplying the Northern Bowen Basin (refer to Figure 5.8). These loads also have the potential to impact the central Queensland to North Queensland (CQ-NQ) grid section. Possible network solutions to address CQ-NQ limitations are discussed in Section 7.3.

Potential solutions

The 132kV network supplying the Northern Bowen Basin has limited thermal capacity and is forecast to reach end of technical service life in the 2040s.

[3] Powerlink, Powerlink 2027-32 Revenue Proposal (Draft), September 2025, pages 66-67.

Powerlink will work with mining proponents to understand their electrification timeline and load ramp-up as proposed developments progress towards commitment. Detailed planning analysis will then inform and optimise the project scopes and cost estimates with Powerlink undertaking the relevant consultation process to identify the preferred option, which may include non-network solutions.

Previous economic assessment of network options for different load development scenarios has identified that advancing the rebuild of the 132kV transmission lines supplying the Northern Bowen Basin area, as higher capacity 132kV lines with associated capacitive compensation for voltage control, is the preferred network option. Powerlink would stage these works to be delivered 'just in time'.

The first stage would rebuild the 132kV double circuit between Nebo and Moranbah, via the Kemmis and Wotonga substations. Based on current customer discussions the earliest need for this rebuild is 2033. To enable a 2033 delivery, a new easement (and/or easement widening) between Nebo and Moranbah substations is required[4].

7.2.3 Lansdown Eco-Industrial Precinct

The Lansdown Eco-Industrial Precinct (LEIP) is located approximately 40 kilometres (km) south of Townsville. The 2,200 hectare (22km^2) precinct is primarily a high impact industrial zone away from residential areas. It is a greenfield development with the vision to become northern Australia's foremost precinct for advanced manufacturing, processing, technology, and emerging industries[5].

Possible tenants of the LEIP include hydrogen production facilities, energy chemicals and quartz manufacturing. The impact of this additional load south of Townsville on the CQ-NQ grid section and possible network solutions to address these impacts is discussed in Section 7.3.

Potential solutions

LEIP has a possible load of up to 900MW within the 10-year outlook period. Supplying this precinct would involve establishing a 275/132kV substation (including lower voltage as required) at LEIP:

- by cutting into two of the existing 275kV circuits between Strathmore and Ross substations, and
- depending on load growth and timing, reinforcing supply via a second double circuit line from CopperString's most eastern substation (Reid River) to LEIP.

In the absence of new generation in northern Queensland, including appropriate levels of firming generation (load flexibility has the potential to reduce this reliance), the LEIP load may result in significant limitations across the CQ-NQ grid section. The resultant delivered load, which would need to be supplied from the CQ-NQ network, will be assessed against the capacity increases achieved by any targeted network augmentations between central and northern Queensland required to support the Energy Roadmap. The assessment will be conducted holistically, also considering the technical end of life drivers of the existing network assets.

7.2.4 Gladstone grid section

Powerlink is progressing the Gladstone Project to deliver essential network upgrades and reinforcements in central Queensland, ensuring ongoing system security and reliability in anticipation of the potential retirement of the Gladstone Power Station[6] in March 2029.

While there are currently no confirmed connection commitments from new direct connect customers in the Gladstone zone at the time of the publication of 2025 TAPR, Powerlink has received a significant number of enquiries for connection of new industrial processing loads. The magnitude and timing of these new loads is uncertain but could reach up to 1,372MW above the Central scenario forecast (refer to Table 2.1).

Depending on where new load growth occurs, limitations may emerge on the 275kV single circuits within the Gladstone area. Additional transmission capacity required to meet this growth will be considered in context of the main network supplying the Gladstone zone, and any downstream network limitations beyond the main transmission system will be assessed based on specific customer requirements.

Network augmentations will be assessed holistically, taking into account technical end of life driver considerations for existing transmission assets and their alignment with hosting energy generation.

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4 A contingent project for reliability of supply in the Northern Bowen Basin (indicative capital cost $1,200 million) is included in Powerlink's Draft Revenue Proposal.

5 Townsville City Council, Lansdown Eco-Industrial Precinct.

6 As noted in Table 5.5, the Gladstone Project was included in the 2024 ISP as an actionable project, progressing under the Queensland Priority Transmission Investment framework. Further detail on the project is in Section 5.6.2, and Powerlink's Final Assessment Report (June 2025) for the project is on our website.

Potential solutions

The projects outlined in Powerlink's Final Assessment Report for the Gladstone Project represent the initial stages of proposed development. These upgrades will provide sufficient power transfer capability to reliably supply the forecast electrical load in the Gladstone area, in anticipation of the potential retirement of Gladstone Power Station and to support the initial electrification of major industries in the Gladstone area.

The initial transmission projects proposed include:

- building a new 275kV high-capacity double circuit line between Calvale and Calliope River substations and install a new 275/132kV transformer at Calliope River Substation
- rebuilding Bouldercombe to Larcom Creek transmission line as a 275kV high-capacity double circuit line
- switching both circuits at a new 275kV substation west of Gladstone.

The amount of additional load that can be supplied in the Gladstone zone following these works will depend on the relative distribution of the load between the Larcom Creek, Calliope River and Wurdong substations, as well as the location of new generation development. Further network augmentations may be required within the Gladstone zone as the load increases. Feasible network solutions could include:

- constructing a new high-capacity 275kV double circuit transmission line between Stanwell and Bouldercombe substations
- additional 275kV tie capacity between Calliope River and Larcom Creek substations
- additional 275kV tie capacity between Calliope River and Wurdong substations
- installation of a flow control device on the Calvale to Wurdong 275kV single circuit
- additional 275kV connections from the Gladstone West Substation to Calliope River and/or Larcom Creek substations.

Powerlink will consider emerging condition-based drivers as part of its planning and consultation processes to ensure cost-effective solutions are delivered for customers.

7.3 Central Queensland to North Queensland grid section

Based on Powerlink's Central scenario forecast and the existing and committed generation (refer to tables 6.1 and 6.2), network limitations impacting reliability are not forecast to occur within the 10-year outlook period.

However, as discussed above, there is the possibility of significant additional load in northern Queensland from new and expanded mines and electrification of existing mining operations in the Northern Bowen Basin, the connection of the North West Minerals Province (NWMP) to the National Electricity Market through CopperString, and development of new load within the LEIP. These loads could increase northern Queensland demand by up to 1,500MW (excluding the NWMP).

Network limitations on the CQ-NQ grid section may arise even if some of these new loads proceed. Power transfer capability into northern Queensland is limited by thermal ratings, voltage and transient stability. The emergence and materiality of network congestion depends on several factors:

- The profile and flexibility of new loads. Historically, southerly power transfers coincide with high solar generation in northern Queensland (refer to Figure 6.14), allowing greater loads to be accommodated during the daylight hours within the existing network capacity.
- Commitment and profile of new generation in northern Queensland. As shown in Figure 6.13, power transfer levels are shifting from northerly to southerly. As more generation connects, more load in northern Queensland can be supported. The adequacy of the CQ-NQ transmission system needs to consider the mix of generation and whether the required firming is sourced from outside northern Queensland.

Emergence of congestion in a northerly direction would first be managed by dispatching additional, out of merit order generation in northern Queensland. As generation costs are higher in northern Queensland due to reliance on liquid fuels, it may be economic to advance the timing of network augmentation to deliver positive net market benefits.

Network augmentation may also be needed as southerly power transfers from northern to central Queensland continue to grow. As shown in Figure 6.13 these power transfers in the southerly direction have steadily increased over time and have historically coincided with high solar generation in northern Queensland (refer to Figure 6.14). As committed generation in northern Queensland enters commercial operation (refer to tables 6.1 and 6.2), this reversal of power flow is expected to increase further.

The CQ-NQ network can host greater generation in northern Queensland if its operation is aligned with high load periods. Notwithstanding the current available transmission headroom, the southerly network capacity between northern and central Queensland may be exceeded in the future. This is largely underpinned by construction of the Eastern Link of CopperString and the associated hosting of new generation within the Flinders region and other anticipated generation development in northern Queensland.

As outlined in Section 7.2.1, CopperString will enable connection of high-quality wind resources in the Flinders region. These wind resources, influenced by equatorial trade winds, exhibit a strong correlation with winter evening peak load periods, a time when other wind resources in central and southern Queensland tend to be less available. This diversity will improve the overall resilience and performance of Queensland's energy mix.

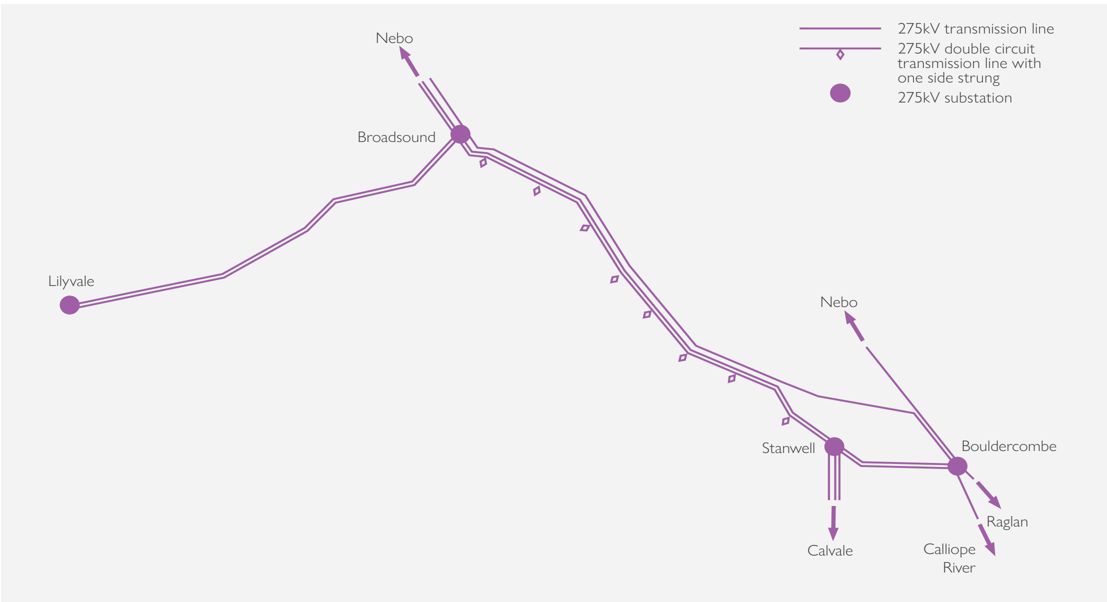
CopperString was modelled as an anticipated project in the 2024 ISP, which identified future projects between northern and central Queensland that deliver net market benefits to customers though they may not be needed until later in the planning horizon. The earliest upgrades, between Bouldercombe, Stanwell and Broadsound, could be needed as early as 2033/34[7]. The Queensland Government's Energy Roadmap also identified that these upgrades increase transfer capacity from north to central Queensland and support new generation connections in north Queensland.

To ensure the CQ-NQ network can efficiently support the development of northern Queensland load and generation expansion requires market modelling across a range of scenarios. Powerlink will continue to work with AEMO (2026 ISP) and QIC to assess whether targeted transmission upgrades will deliver net market benefits. These assessments will consider any emerging condition-based drivers as part of the longer-term planning process and in conjunction with the ISP and Energy Roadmap.

Possible solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with only one circuit strung (refer to Figure 7.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second side of this transmission line. No new easement is required for this scope of work.

Figure 7.1 Stanwell/Broadsound area transmission network



As discussed in Table 5.12 and Appendix E, there are condition-based factors driving reinvestment on the following circuits between central and northern Queensland:

- Bouldercombe and Nebo – reinvestment within 10 years
- Bouldercombe and Broadsound – reinvestment within 10 years.

[7] AEMO 2024 Step Change scenario forecast.

To address network capacity constraints, Powerlink and AEMO (through the ISP) will assess whether it is prudent and efficient to advance the staged rebuild of these lines as higher capacity double circuit 275kV lines[8]. This could involve:

- constructing a 275kV high-capacity double ciruit line between Bouldercombe and Broadsound substations (via Stanwell)
- constructing a double circuit 275kV high-capacity line between Broadsound and Nebo substations
- decommissioning or make safe the individual circuits identified above.

Powerlink will consider these investments holistically, ensuring alignment with technical asset life, network hosting requirements, and cost-effective outcomes for customers.

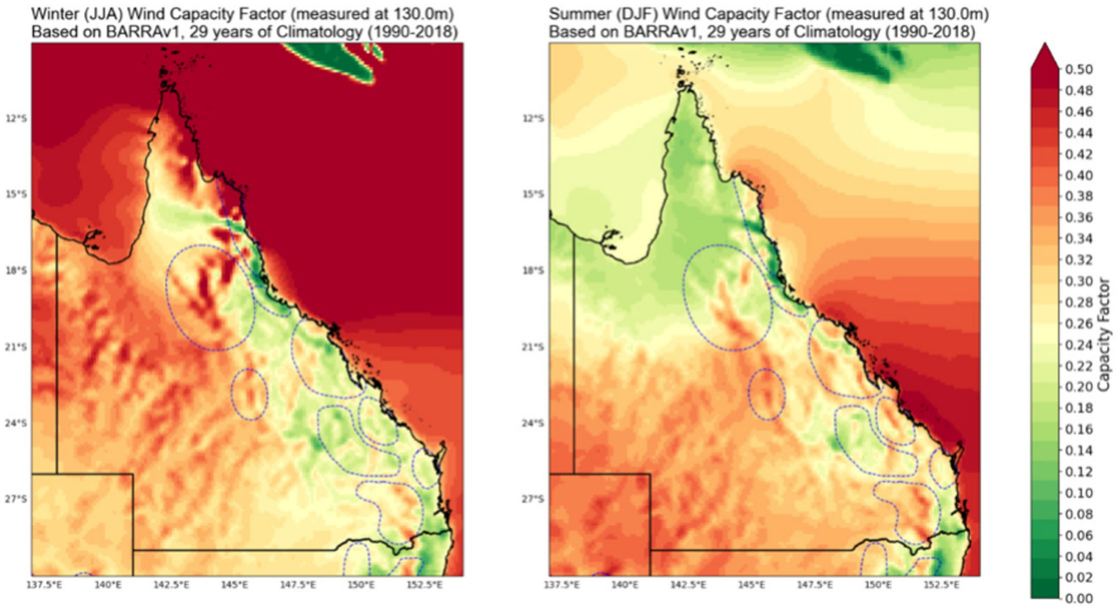
7.4 Central Queensland to South Queensland grid section

The central Queensland to South Queensland (CQ-SQ) corridor is recognised as a key enabler for the energy system in AEMO's 2024 ISP. The 2024 ISP identifies and actionable project for a new coastal 500kV transmission line connecting the Borumba PHES project from Powerlink's Halys Substation through into central Queensland (refer to Table 5.5).

Since the release of AEMO's 2024 ISP, Powerlink analysis has shown inland wind resources offer consistently higher capacity factors than those along the coast for both summer and winter seasons (refer to Figure 7.2). This finding has been further supported by market engagement.

In response, Powerlink has broadened its focus to a more inland transmission route. The inland CQ-SQ transmission development can be staged and paced to align with interest from new generation connections. The shift has also enabled the connection of the Borumba PHES to be reassessed. If Borumba PHES proceeds, it will now be connected at 275kV.

Figure 7.2 Seasonal wind capacity factor data



Note:

(1) Source: Bureau of Meteorology.

Ongoing investment in the existing coastal transmission lines remains essential to maintain reliability of supply and efficient power transfer. As outlined in Section 5.7.1, the coastal corridor of the CQ-SQ grid section was constructed in the 1970s and 1980s. It consists of single circuit 275kV transmission lines between Calliope River and South Pine substations. These coastal network assets are expected to reach the end of their technical service life within the next 20 years. A key consideration is that this corridor is comprised solely of single circuit 275kV towers that may make cost-effective refit strategies less viable compared to double circuit tower rebuilds.

Overlaying these emerging condition drivers is the enduring need to deliver a CQ-SQ transmission network with sufficient power transfer capacity to support efficient market outcomes.

8 A contingent project for CQ-NQ augmentation (indicative capital cost $1,900 million) is included in Powerlink's Draft Revenue Proposal.

Accordingly, Powerlink is actively progressing a holistic planning approach for the coastal 275kV CQ-SQ corridor, recognising its strategic importance in accommodating emerging generation interests such as the Mt Rawdon PHES project.

Central to this strategy is ongoing condition monitoring of the existing single circuit lines, with plans to upgrade thermal capacity and progressively rebuild sections as high-capacity double circuit 275kV high temperature conductor (HTC) lines, when it is economic to do so. The commitment of Mt Rawdon PHES may be a key trigger for this augmentation.

Powerlink continues to assess congestion risks and operational constraints across both inland and coastal corridors, ensuring that connection options, such as cut-ins, are evaluated for technical feasibility, long-term system security and market benefit. This integrated approach enables Powerlink to align infrastructure upgrades with broader energy system priorities, ensuring the CQ-SQ network remains resilient and capable of supporting both firming assets and other new generation sources.

7.5 Unlocking generation expansion in Darling Downs and Surat areas

Powerlink is taking a prudent, options-led approach to future CQ–SQ transmission upgrades, informed by system needs, market conditions and stakeholder input. The strategic shift to consider a more westerly inland corridor for future CQ-SQ transmission capability upgrades is pivotal to unlocking new generation potential in the Darling Downs and Surat regions. This inland corridor enables efficient management of congestion forecast to emerge within the 275kV Surat network as generation projects in these areas progress.

Potential solutions

A 275kV corridor between the Wandoan South Substation and a future mid-point switching substation on the existing Calvale to Halys 275kV double circuit line near Auburn River would unlock generation hosting capacity in the Darling Downs and Surat areas.

The primary trigger for progressing such development would be the emergence of congestion on the Surat 275kV network. Powerlink is committed to evaluating a range of infrastructure solutions, including establishing a 275kV connection to the inland CQ-SQ corridor, to ensure efficient utilisation of the existing assets between Halys, Calvale and Gladstone. The strategy enables increased intra-regional power transfer and supports a staged development of transmission infrastructure to respond flexibly to market conditions and the progress of new generation projects. The staged inland CQ-SQ development could include:

- constructing a new high-capacity double circuit transmission line between Auburn River and Calvale substations
- constructing a new high-capacity double circuit transmission line between Auburn River and Halys substations.

These potential developments are designed to meet growing load in southern Queensland and the Gladstone areas. The expansion of hosting capacity in the Darling Downs and Surat zones is aligned with supporting Queensland's energy transition and industrial growth in Gladstone. The infrastructure will support scenarios involving large-scale electrification and industrial transformation. Powerlink is investigating land for substations and easements.

7.6 Unlocking generation expansion in Southern Downs area

Powerlink is closely monitoring the new generation commitments within the Southern Downs and the Queensland to New South Wales Interconnector (QNI) corridor, particularly following the completion of the QNI Minor Project. This upgrade has increased the transfer capacity between northern New South Wales (NSW) and southern Queensland, with inter-network testing almost completed to release its full designed capacity, 950MW from northern NSW to southern Queensland and 1,450MW in the reverse direction.

While this increased inter-regional power transfer capability supports energy and reserve sharing, it also increases the risk of congestion between Southern Downs and South East Queensland.

Potential solutions

AEMO's 2024 ISP identified that under the Step Change scenario, a future transmission project may be required around 2034/35 to alleviate congestion. To address congestion and drive efficient market outcomes, both network and non-network responses are being considered:

- replace 330/275kV T4 transformer at Middle Ridge Substation with a larger transformer (1,650MVA)
- install additional 330/275kV transformer capacity at Braemar Substation with or without joining the Braemar 275kV switchyard buses (and addressing any associated fault level limitations)

- install phase shifting transformers at Tummaville Substation (with and without the T4 transformer replacement at Middle Ridge Substation)
- generation tripping or runback paired with a generation response Battery Energy Storage System (BESS) in South East Queensland
- System splitting scheme, together with any required additional system strength (could also be paired with a BESS response in South East Queensland).

In the 2024 ISP, AEMO identified a QNI Connect Project as an actionable ISP project. Powerlink's consideration of technically feasible options will, in addition to delivering increased inter-regional power transfer capability, investigate whether unlocking more generation hosting capacity in the Southern Downs and QNI areas is also efficient.

7.7 Addressing limitations between western and northern Brisbane

There are emerging network limitations between Blackwall and South Pine substations. Limitations may occur following outages of either the Tarong to South Pine or Mt England to South Pine 275kV circuits. System conditions leading to this congestion include high loads in Moreton north and lower generation levels in central and northern Queensland.

A future transmission project may be required by the early 2030s to address this limitation. To address congestion and drive efficient market outcomes, a network response could include:

- constructing a new 3.4km double circuit 275kV transmission line on the spare easement between Blackwall and Karana Downs substations. This includes rearranging the circuits to establish a double circuit between Blackwall and South Pine substations and as well as a double circuit between Blackwall and Rocklea substations.

7.8 QNI Connect

The QNI Connect project was identified as an actionable project in the 2024 ISP. The indicative timing for the project under AEMO's Step Change scenario was 2032/33.

Powerlink and Transgrid are jointly responsible for progressing QNI Connect through the Regulatory Investment Test for Transmission process. This includes publishing the Project Assessment Draft Report by 25 June 2026.

The candidate ISP project was a 330kV double circuit line from New England to Dumaresq, Bulli Creek, and Braemar (western route), with estimated benefits of $190 million and a capital cost of $1.66 billion (2023) excluding risk and contingency[9].

Since the 2024 ISP, AEMO has identified real cost increases of 25–55% for overhead transmission lines and 10–35% increases for substations, compared to 2024 ISP estimates[10]. These higher costs, along with extended lead times, will be factored into AEMO's 2026 ISP to reassess the possible timing and status of ISP projects. AEMO will publish a Draft 2026 ISP in December 2025.

7.9 Easement acquisition activities

Powerlink is committed to early and meaningful engagement with stakeholders impacted by our network development activities. This includes introducing more structured processes for ensuring ongoing community and landholder engagement in corridor selection and easement acquisition processes. It can mean projects take longer to deliver, but ongoing engagement is important as part of the broader focus on ensuring community benefit and social value can be delivered as part of our program of works.

Powerlink's aim is to ensure an appropriate balance between achieving strong social performance outcomes critical for ongoing delivery of new transmission network infrastructure, and timely delivery of strategic project investment.

Robust planning and the early initiation of targeted easement acquisition activities is therefore an important factor in ensuring strategic projects can be delivered within potential timeframes, should the need arise. Equally important is strong engagement with customers, market participants and communities on Powerlink's longer-term plans for easement acquisition.

Over the coming months, Powerlink will continue to shape and refine its approach to identifying priority easement activities that are needed to support the timely and socially responsible delivery of future transmission projects.

[9] A contingent project for QNI Connect (indicative capital cost $1,500 million for the Queensland component) is included in Powerlink's Draft Revenue Proposal.

[10] AEMO, 2025 Electricity Network Options Report, July 2025, page 31.

Recently commissioned and committed network developments

08

08. Recently commissioned and commited network developments

This chapter provides information on the status of customer connection works and transmission network projects since publication of the 2024 Transmission Annual Planning Report (TAPR). It presents a snapshot of recently commissioned projects and projects that are committed or awaiting commencement since completion of the Regulatory Investment Test for Transmission (RIT-T), as well as the status of asset retirement works.

Key highlights

- During 2024/25, Powerlink's delivery efforts remained predominantly directed towards connecting generation and reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's regulated investment program focuses on reducing the identified risks arising from assets reaching the end of technical service life and maintaining network resilience, while continuing to deliver safe, reliable and cost-effective transmission services to our customers.
- Powerlink has completed one augmentation and four reinvestment projects since the publication of the 2024 TAPR.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland.
- Since the publication of the 2024 TAPR, two connection projects have been completed enabling an additional 632 megawatts (MW) of generation.
- Additionally, four Battery Energy Storage System (BESS) connections have been completed since publication of the 2024 TAPR.

8.1 Introduction

For all proposed network augmentations and replacements of network assets, the National Electricity Rules (NER):

- requires the TAPR to detail the month and year the project/asset will become operational
- notes that the level of detail should be sufficient, relative to the size or significance of the project[1].

A geographic representation of Powerlink's transmission network is shown in Figure 8.1 at the end of this chapter.

The status of projects reported in this chapter is as at 30 September 2025.

8.2 Connection works

Table 8.1 lists connection works commissioned since Powerlink's 2024 TAPR was published.

Table 8.1 Commissioned connection works since October 2024

Project (1) (2)	Purpose	Zone	Date commissioned (3)
Aldoga Solar Farm	New Solar Farm	Gladstone	Quarter 4 2024/25
Ulinda Park BESS	New BESS	South West	Quarter 4 2024/25
Wambo Wind Farm Stage 1 (2)	New Wind Farm	South West	Quarter 3 2024/25
Tarong BESS	New BESS	South West	Quarter 1 2025/26
Brendale BESS	New BESS	Moreton	Quarter 1 2025/26
Greenbank BESS	New BESS	Moreton	Quarter 3 2024/25

Notes:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(2) Powerlink has completed the scope of works for this project. Remaining works associated with generation connection are being coordinated with the customer.

(3) Commissioning dates reflect the financial year quarter in which they occurred.

(4) Refer to Table 6.1 for information on the available MW capacity of generators connected or committed to be connected to Powerlink's transmission network.

[1] National Electricity Rules, clause 5.12.2(c)(5)(i).

08. Recently commissioned and commited network developments

Table 8.2 lists new transmission connection works for generating systems that are committed and under construction as at October 2025. These connection projects resulted from agreements reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 8.2 Committed and under construction connection works as at October 2025

Project (1) (2)	Purpose	Zone	Proposed commissioning date (3)
Kidston Pumped Storage Hydro	New pumped hydro energy storage	Ross	Quarter 2 2025/26
Broadsound Solar Farm	New Solar Farm	Central West	Quarter 2 2025/26
Lotus Creek Wind Farm	New Wind Farm	Central West	Quarter 1 2026/27
Boulder Creek Wind Farm	New Wind Farm	Central West	Quarter 4 2026/27
Woolooga BESS	New BESS	Wide Bay	Quarter 3 2025/26
Punchs Creek Solar Farm	New Solar Farm	Bulli	Quarter 4 2026/27
Wambo Wind Farm Stage 2	Expansion of Wind Farm	South West	Quarter 3 2025/26
Supernode (South Pine) BESS	New BESS (4)	Moreton	Quarter 3 2025/26
Swanbank BESS	New BESS	Moreton	Quarter 2 2025/26

Notes:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, industrial development or mine), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(2) Refer to Table 6.1 for information on the available MW capacity of generators connected or committed to be connected to Powerlink's transmission network.

(3) Proposed commissioning dates reflect the financial year quarter in which projects are anticipated to be commissioned at the time of the 2025 TAPR publication.

(4) Powerlink's scope of works for Supernode 1 has been completed. Remaining works associated with generation connection are being coordinated with the customer. Supernode 2 is under construction at the time of 2025 TAPR publication.

8.3 Network Developments

Table 8.3 lists network developments that have been commissioned since October 2024.

Table 8.3 Commissioned network developments since October 2024

Project	Purpose	Zone	Date commissioned
Belmont 275kV bus reactor	Maintain voltages in the Moreton zone	Moreton	November 2024

Table 8.4 list network developments that are committed and under construction at October 2025.

Table 8.4 Committed network developments as at October 2025

Project	Purpose	Zone	Proposed commissioning date
Establishment of a 3rd 275kV connection into Woree	Maintain supply reliability in the Far North zone	Far North	December 2025 (1)

Note:

(1) The 275kV feeder between Woree, Ross and Tully South substations was commissioned in September 2024. The completion of remaining minor works is expected by December 2025.

8.4 Network Reinvestments

Table 8.5 lists network reinvestments commissioned since Powerlink's 2024 TAPR was published.

Table 8.5 Commissioned network reinvestments since October 2024

Project	Purpose	Zone	Date commissioned
Woree SVC secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	March 2025
Ross 275/132kV transformers life extension	Maintain supply reliability in the Ross zone	Ross	November 2024
Kemmis secondary systems replacement	Maintain supply reliability in the North zone	North	December 2024
Mudgeeraba 275kV secondary systems replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	December 2024

Table 8.6 lists network reinvestments which are committed as at October 2025.

Table 8.6 Committed network reinvestments as at October 2025

Project	Purpose	Zone	Proposed commissioning date
Woree secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2025
Chalumbin secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2025
Cairns secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2025
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations (section between Davies Creek and Bayview Heights)	Maintain supply reliability to the Far North and Ross zones (1)	Far North	January 2026
Innisfail 132kV secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	June 2027
Line refit works on the 132kV transmission line between Townsville South and Clare South substations	Maintain supply reliability in the Ross zone	Ross	March 2026
Garbutt configuration change	Maintain supply reliability in the Ross zone	Ross	January 2026
Townsville South secondary systems replacement Stage 1	Maintain supply reliability in the Ross zone	Ross	February 2026
Townsville South 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	July 2026
Ross 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	December 2025
Ross 275kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	March 2026
Nebo 132/11kV transformers replacement	Maintain supply reliability in the North zone	North	December 2025
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek substations	Maintain supply reliability in the North zone (1)	North	December 2025
Newlands 132kV primary plant replacement	Maintain supply reliability in the North zone	North	December 2026
Dysart 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (1)	Central West	October 2026
Blackwater 66kV CT and VT replacement	Maintain supply reliability in the Central West zone	Central West	August 2026
Blackwater 132/66kV transformers replacement	Maintain supply reliability in the Central West zone	Central West	October 2027
Lilyvale 275kV and 132kV primary plant replacement	Maintain supply reliability in the Central West zone	Central West	June 2026
Egans Hill secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	August 2026
Gladstone South secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	February 2027
QAL West secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	February 2027
Tangkam 110kV secondary systems replacement	Maintain supply reliability in the South West zone	South West	September 2026
Sumner 110kV secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	September 2026
Belmont 11kV underground cable and transformers replacement	Maintain supply reliability in the Moreton zone	Moreton	September 2026

Table 8.6 Committed network reinvestments as at October 2025 (*continued*)

Project	Purpose	Zone	Proposed commissioning date
Redbank Plains 110/11kV transformers and selected primary plant replacement	Maintain supply reliability in the Moreton zone	Moreton	October 2026
Mt England 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	December 2026

Note:

(1) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

8.5 Uncommitted Regulatory Investment Test for Transmission projects

Table 8.7 lists network investments which have undergone the Regulatgory Investment Test for Transmission (RIT-T) and are not fully committed as at October 2025.

Table 8.7 Uncommitted network investments as at October 2025

Project	Purpose	Zone	Proposed commissioning date
Kemmis 132/66kV transformer replacement	Maintain supply reliability in the North zone (1)	North	November 2026
Central Queensland synchronous condensers	Maintain supply reliability in the Gladstone and Central West zones (2)	Gladstone	March 2029
Tarong 275/66kV transformers and selected primary plant replacement	Maintain supply reliability in the South West zone (1)	South West	June 2028
Chinchilla 132kV primary plant and secondary systems replacement	Maintain supply reliability in the South West zone (1)	South West	June 2027

Notes:

(1) Capital expenditure in relation to network asset replacement.

(2) Capital expenditure in relation to system services.

8.6 Asset Retirement Works

There were no asset retirements that were completed since the publication of the 2024 TAPR.

Table 8.8 lists asset retirement works as at October 2025.

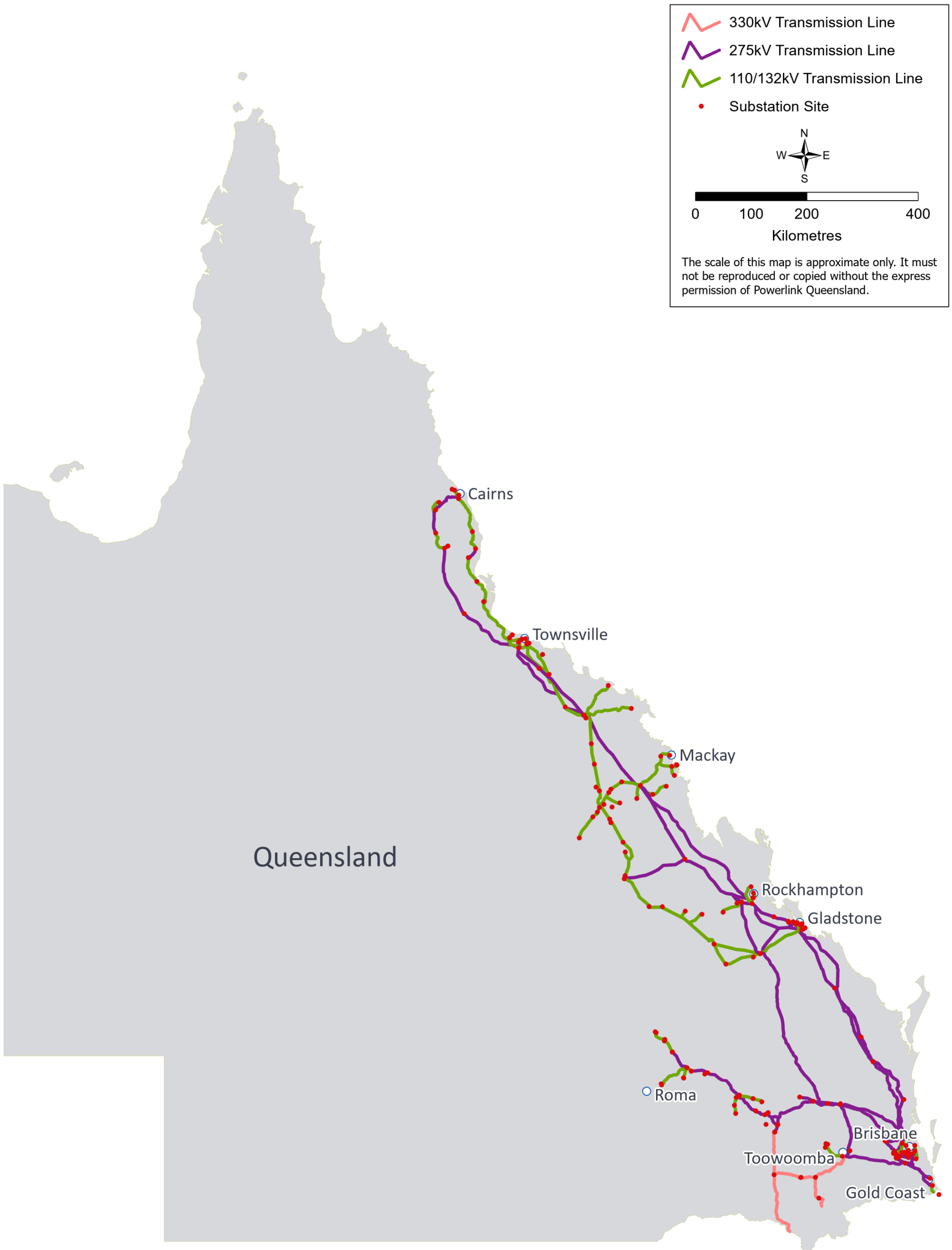
Table 8.8 Asset retirement works as at October 2025 (1)

Project	Purpose	Zone	Proposed retirement date
132kV transmission line retirement between Woree and Kamerunga substations	Removal of asset at the end of technical life	Far North	June 2032
Cairns 132/22kV Transformer 4 retirement	Removal of asset at the end of technical life	Far North	December 2027
132kV transmission line retirement between Townsville South and Clare South substations	Removal of assets at the end of technical life	Ross	June 2029
Lilyvale 132/66kV transformer retirement	Removal of asset at the end of technical life	Central West	June 2026
Tarong 275/132kV transformers retirement	Removal of assets at the end of technical life	South West	August 2026

Note:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 8.1 Existing Powerlink Queensland transmission network as at October 2025



Appendices

Appendix A Planning criteria, responsibilities and processes

This appendix provides an overview of Powerlink's planning criteria, responsibilities and processes.

A.1 Powerlink's asset planning criteria

The Queensland Government amended Powerlink's N-1 criterion in 2014 to allow for increased flexibility. The planning standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event. The following limits are placed on the maximum load and energy that may be at risk of not being supplied during a critical contingency:

- will not exceed 50 megawatts at any one time
- will not be more than 600 megawatt hours in aggregate.

The risk limits can be varied by:

- a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services, or
- agreement with the Queensland Energy Regulator.

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits set out above are exceeded or when the probability weighted economic cost of load at risk of not being supplied justifies the cost of the investment. Therefore, the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required. Powerlink will continue to maintain and operate its transmission network to maximise reliability to customers.

Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations, including the risks arising from ageing network assets remaining in-service. These responsibilities also extend to joint planning with other network service providers (NSP) to determine the most cost-effective solution regardless of the asset boundaries.

Energex and Ergon Energy (part of the Energy Queensland Group) are the two major Distribution Network Service Providers (DNSPs) in Queensland and were issued amended Distribution Authorities from July 2014. The service levels defined in the Distribution Authorities differ to that of Powerlink's authority. Joint planning accommodates these different planning standards by applying the planning standard consistently with the owner of the asset which places load at risk during a contingency event.

Powerlink has established policy frameworks and methodologies to support its planning standard. These are being applied in various parts of the Powerlink network where possible emerging limitations are being monitored.

A.2 Planning processes

Powerlink has obligations that govern how it should address forecast network limitations. These obligations are prescribed by the *Electricity Act 1994* (Electricity Act), the National Electricity Rules (NER) and Powerlink's Transmission Authority.

The Electricity Act requires that Powerlink ensure as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid[1].

It is a condition of Powerlink's Transmission Authority that it meets licence and NER requirements relating to technical performance standards during intact and contingency conditions. The NER sets out minimum performance requirements of the network and connections and requires that reliability standards at each connection point be included in the relevant connection agreement.

The requirements for initiating solutions to meet forecast network limitations, procurement of system strength or inertia services, or the need to address the risks arising from ageing network assets remaining in-service, including new regulated network developments or non-network solutions, are set out in the NER[2]. Planning processes require consultation with Australian Energy Market Operator (AEMO), Registered Participants and interested parties, including customers, generators, DNSPs and other Transmission Network Service Providers (TNSPs).

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Each of these clauses prescribes a slightly different consultation process. The Regulatory Investment Test for Transmission (RIT-T) is the most common NER consultation process undertaken by Powerlink. Powerlink continues to publish information and consult with potential providers of non-network solutions for the provision of system security service needs as identified by AEMO.

1 *Electricity Act 1994* (Qld), section 34(2).
2 National Electricity Rules, clauses 5.14.1, 5.16.4, 5.16A, 5.20B, 5.20C and 5.22.14.

A.3 Integrated planning of the shared network

Significant inputs to Powerlink's network planning process are the:

- forecast of customer electricity demand, including demand side management (DSM), and its location
- location, capacity and arrangement of existing, new and retiring generation (including embedded generation)
- condition and performance of assets and an assessment of risks arising from ageing network assets remaining in-service
- assessment of future network capacity to meet the required planning criteria and efficient market outcomes, including system strength and the potential to facilitate future storage requirements to firm intermittent renewable generation and help address minimum demand.

Powerlink uses 10-year forecasts of electrical demand and energy across Queensland, together with forecast generation patterns, to determine potential flows on transmission network elements. The location and capacity of existing, retiring and committed generation in Queensland is sourced from AEMO, unless modified following advice from relevant market participants. Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSPs and AEMO.

Powerlink examines the capability of its existing network and the future capability following any changes resulting from:

- committed network projects (for both augmentation and to address the risks arising from ageing network assets remaining in-service)
- the impact of generation retirements on transmission network power flows, system strength and reactive power capability
- existing and future generation developments
- variances in Powerlink's operating environment or changes in technical characteristics such as minimum demand, inertia and system strength as the power system continues to evolve.

This includes consultation with the relevant DNSP in situations where the performance of the transmission network may impact on, or be impacted by, the distribution network, such as where the two networks operate in parallel.

Where potential flows could exceed network capability, Powerlink notifies market participants of these forecast emerging network limitations. If the capability violation exceeds the required reliability standard, joint planning investigations are carried out with DNSPs (or other TNSPs if relevant) in accordance with the NER[3]. The objective of this joint planning is to identify the most cost-effective solution, regardless of asset boundaries, including potential non-network solutions.

Powerlink maintains its network to manage risks associated with asset condition and performance. A program of asset condition assessments helps identify emerging risks.

As assets approach the end of their technical service life, Powerlink evaluates a range of reinvestment strategies, using a flexible, integrated approach. This considers network topography and capacity, current and future needs, including future generation developments, electrification and emerging industries.

Changing power system flows and patterns require ongoing reassessment of network capacity. Reinvestment decisions are made in context – not in isolation or on a like-for-like basis. Strategies reflect enduring need, the role of transmission in the energy transition and the interconnected nature of the high voltage (HV) system across regions or corridors. Non-network solutions are also considered as part of this integrated planning.

By combining asset condition, demand limitations and energy transition goals, Powerlink delivers cost-effective solutions that support reliability and address risks from aging infrastructure.

The planning process includes evaluating a broad range of options, as outlined in Table A.1, and considers future capacity needs and opportunities to adopt new, cost-effective and technically feasible technologies.

3 AER, Industry Practice Application Note for Asset Replacement Planning, July 2024.

Table A.1 Examples of planning options

Option	Description
Non-network alternatives	Non-network solutions are not limited to but may include network support and system services from existing and/or new generation, DSM initiatives (either from individual providers or aggregators), and other forms of technologies (such as battery installations). These solutions may reduce, negate or defer the need for network investments.
Network reconfiguration	The assessment of future network requirements may identify the reconfiguration of existing assets as the most economical option. This may involve asset retirement coupled with the installation of plant or equipment at an alternative location that offers a lower-cost substitute for the required network functionality.
Asset de-rating or retirement	May include strategies to de-rate, decommission and/or demolish an asset and is considered in cases where needs have diminished in order to achieve long-term economic benefits.
Augmentation	Increases the capacity of the existing transmission network; for example, the establishment of a new substation, installation of additional plant at existing substations or construction of new transmission lines. This is driven by the need to meet prevailing network limitations and customer supply requirements, or where there may be net economic benefits to customers.
System Services	The assessment of future network requirements to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services, inertia and reactive power services.
Reinvestment	Asset reinvestment planning ensures that existing network assets are assessed for their enduring network requirements in a manner that is economic, safe and reliable. This may result in like-for-like replacement, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity. Condition and risk assessment of individual components may also result in the staged replacement of an asset where it is technically and economically feasible.
Line refit	Powerlink utilises a line reinvestment strategy called line refit to extend the service life of a transmission line and provide cost benefits through the deferral of future transmission line rebuilds. Line refit may include structural repairs, foundation works, replacement of line components and hardware, abrasive blasting and painting.
Transformer life extension	Powerlink utilises a transformer reinvestment strategy called transformer life extension to extend the service life of a transformer to provide cost benefits through the deferral of the timing for a future transformer replacement. Transformer life extension may include replacement of components such as high voltage bushings, tap changers and instruments, addressing sources of oil leaks such as replacement of gaskets and main lid sealing, replacement of transformer oil, and addressing radiator corrosion.
Operational measures	Network constraints may be managed during specific periods using short term operational measures; for example, switching of transmission lines or redispatch of generation in order to defer or negate network investment.

A.4 Powerlink's reinvestment criteria

Powerlink is committed to ensuring the sustainable long-term performance of its assets to deliver safe, reliable and cost-effective transmission services to customers, stakeholders and communities across Queensland. Powerlink demonstrates this by adopting a proactive approach to asset management that optimises whole of life cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

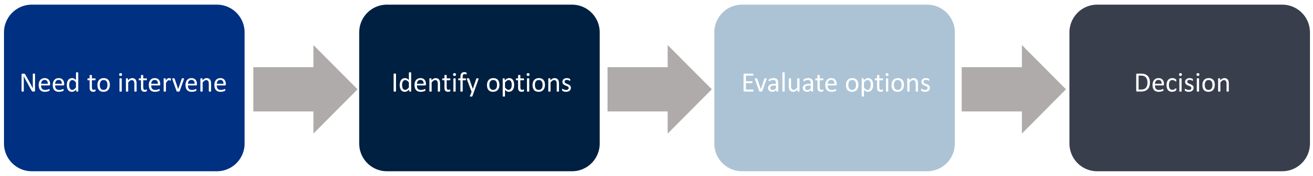
A4.1 The reinvestment criteria framework

The reinvestment criteria framework defines the methodology that Powerlink uses to assess the need and timing for intervention on network assets to ensure industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling Powerlink's customers and stakeholders to better understand the criteria to determine the need and timing for asset intervention. The reinvestment criteria framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention is defined when business as usual activities (including routine inspections, minor condition-based and corrective maintenance and operational refurbishment projects) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Powerlink's asset reinvestment process (refer to Figure A.1) enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure A.1 Asset Reinvestment Process



A4.2 Asset Reinvestment Review

In 2023 Powerlink completed a review of its approach to network asset reinvestment, with a focus on overhead transmission lines, to ensure consistency with contemporary asset management and risk-based decision frameworks. In particular, the review considered Powerlink's approach to line refit work that aims to achieve a life extension of a nominal 15 years across an entire asset, bundled in a single up-front intervention.

The Asset Reinvestment Review Working Group was established to ensure customers and the Australian Energy Regulator were actively involved in the review and its recommendations. The Asset Reinvestment Review Working Group Report was published in May 2023. A key recommendation in the report was for Powerlink to model existing and alternative bundling approaches for future transmission line refit investment decisions, and to progress the most cost-effective solution based on detailed condition and cost information, while allowing for developing network needs. It was also recommended that compliance works are only undertaken on structures where condition-based work is to be performed, and that Powerlink retain the existing asset definition for transmission lines[4].

[4] Powerlink Queensland, Asset Reinvestment Review, working group report, June 2023.

Appendix B Asset management overview

This appendix provides an overview of Powerlink's approach to asset management.

B.1 Introduction

Powerlink's Asset Management System forms part of Powerlink's Business Strategy, and is integral to managing and monitoring assets across the asset life cycle and captures key internal and external drivers and initiatives for the business.

Factors that influence network development, such as energy and demand forecasts, generation development, emerging industry trends and technology, and risks arising from the condition and performance of the existing asset base, are analysed collectively to support integrated network planning over a 10-year period.

B.2 Overview of approach to asset management

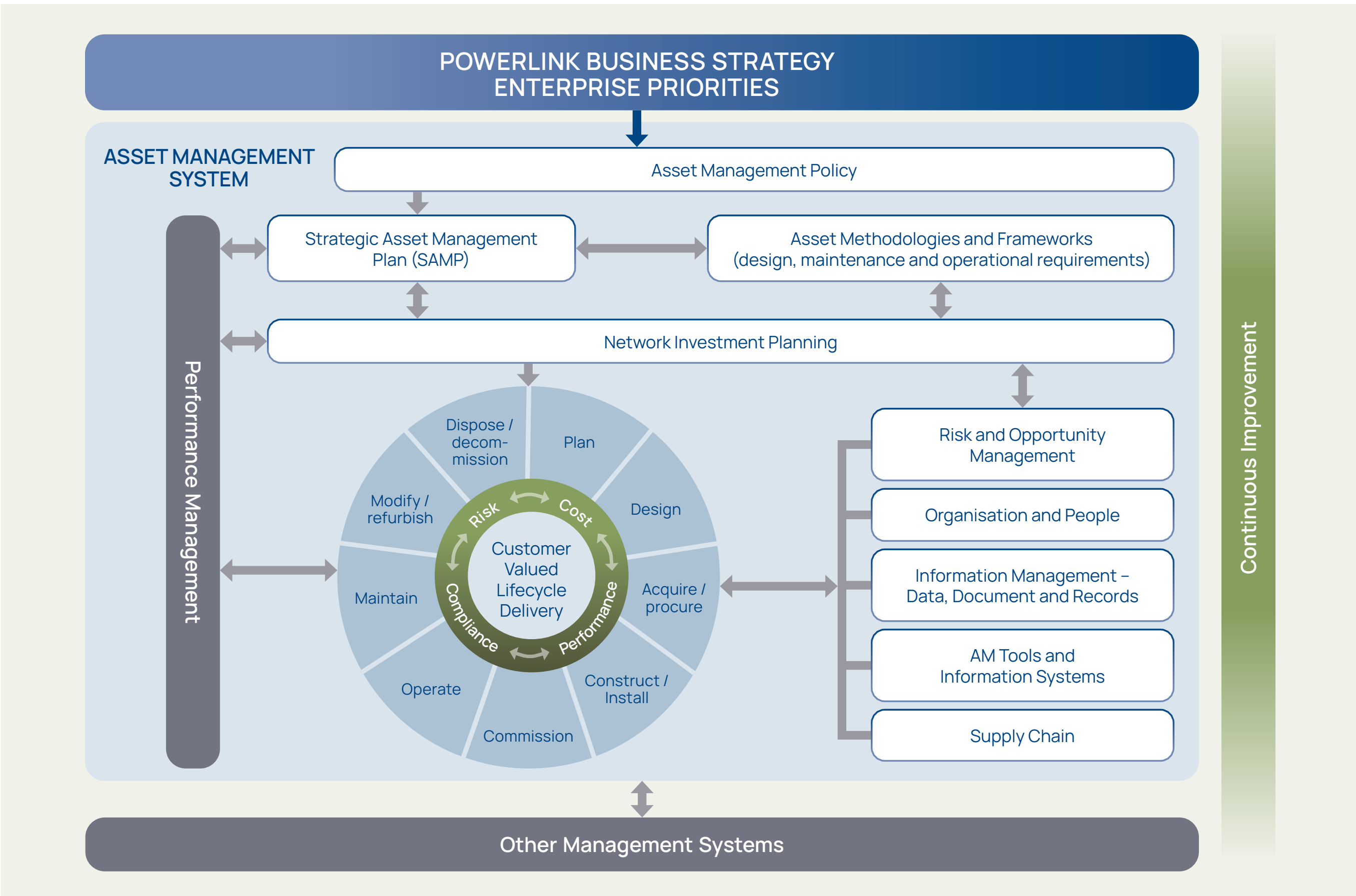
Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver safe, reliable and cost-effective services.

Asset management is a critical aspect of Powerlink's operations, ensuring efficient management of assets and optimal utilisation of resources. Figure B.1 illustrates the relationships and linkages between the Asset Management Policy, Strategic Asset Management Plan (SAMP), and other components of the Asset Management System.

Powerlink's asset management and joint planning approach ensures asset reinvestment needs consider the enduring need and most cost-effective options as opposed considering only like-for-like replacements. A detailed analysis of both asset condition and network capability is performed prior to proposed reinvestment and where applicable, a Regulatory Investment Test for Transmission (RIT-T) is undertaken in order to bring about optimised solutions that may involve network reconfiguration, retirement and/or non-network solutions (Refer to Appendix A and Section 5.3).

Powerlink's asset management approach is committed to achieving sustainable practices that ensure Powerlink provides a valued transmission service to meet customers' needs by optimising whole of life cycle costs, benefits and risks and ensuring compliance with applicable legislation, regulations and standards.

Figure B.1 Asset management overview



B.3 Powerlink's Asset Management System

The Asset Management System at Powerlink enables assets to be managed strategically, in line with corporate objectives and in coordination with other management systems.

Underpinning this system is the Asset Management Policy which sets out the principles to be applied for making asset management decisions as well as ensuring delivery of these decisions. The Asset Management Policy aligns Powerlink's strategic objectives with customer and stakeholder requirements.

The SAMP is developed based on Asset Management Policy principles which are used to inform asset management methodologies and activities. The SAMP and other asset management methodologies consider the need to continually improve asset management practices.

Powerlink undertakes periodic reviews of network assets considering a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and ongoing supportability.

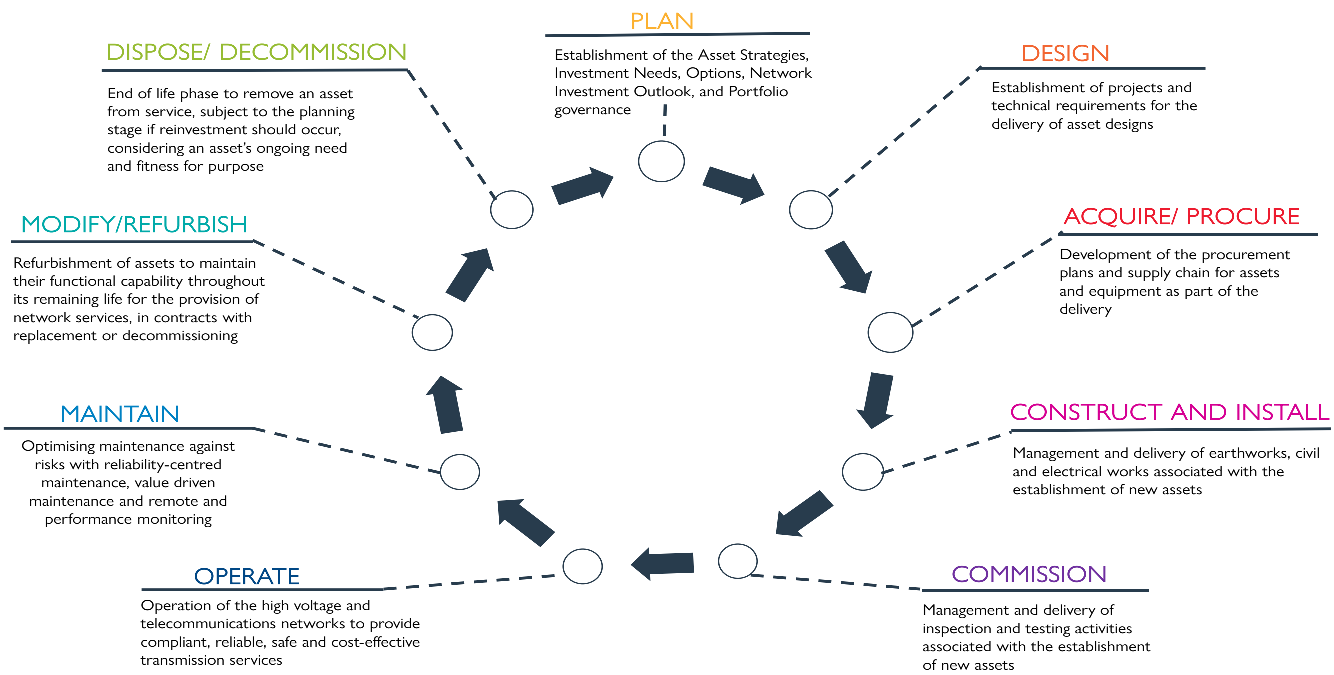
Asset methodologies provide whole of life cycle management for each asset category (transmission lines, substations, digital assets, land assets and underground cables) to inform the delivery of asset life cycle stages.

All asset management related activities are undertaken by applying relevant procedures, specifications and guidelines for delivering each stage of an asset life cycle activity.

Asset information is key for Powerlink's asset management with asset data, information and knowledge used to inform a range of asset management and investment decision making processes. Asset information comes from the analysis of asset data which is used to inform decisions on how Powerlink's assets are managed for both short term operational purposes and longer-term strategic plans.

Life cycle delivery establishes how and what is needed for asset decisions and activities in consideration of the Asset Management System. Powerlink defines asset life cycle and main activities throughout the nine stages shown in Figure B.2.

Figure B.2 Powerlink's Asset Life cycle Stages



B.4 Flexible and integrated network investment planning

A fundamental element of the Asset Management System involves processes to manage the life cycle of assets, from planning and investment to operation, maintenance and refurbishment, and end of technical service life.

A range of options are considered as part of a flexible and integrated approach to network investment planning. These options may include retiring or decommissioning assets where there is unlikely to be an ongoing future need, refurbishing to maintain the service life of assets, replacing assets with different capacity or type to match needs, alternate network configuration opportunities, and non-network solutions.

The purpose of Powerlink's network investment planning is to:

- apply the principles set out in Powerlink's Asset Management Policy, SAMP and related processes to guide network asset planning and reinvestment decisions
- provide an overview of asset condition and health, life cycle plans and emerging risks related to factors such as safety, network reliability, resilience and obsolescence
- provide an overview and analysis of factors that impact network development, including energy and demand forecasts, generation developments, forecast network performance and capability, and the condition and performance of Powerlink's existing asset base
- identify potential opportunities for optimisation of the transmission network
- provide the platform to enable the transformation to a more sustainable, cost-effective and climate resilient power system.

B.5 Asset Management Implementation

Powerlink has adopted implementation strategies across its portfolio of projects and maintenance activities aimed at efficiently delivering the overall work program, including prudent design standardisation by considering emerging trends in technology, portfolio management and supply chain management.

One of Powerlink's objectives includes the efficient implementation of work associated with network operation, field maintenance and project delivery. Powerlink continues to pursue innovative work techniques that:

- reduce risk to personal safety
- optimise maintenance and/or operating costs
- reduce the requirement for and minimise the impacts of planned outages on the transmission network.

In line with good practice, Powerlink also undertakes regular auditing of work performed to facilitate the continuous improvement of the overall Asset Management System.

B.6 Further information

Further information on Powerlink's Asset Management System may be obtained by emailing NetworkAssessments@powerlink.com.au.

Appendix C Joint planning

This appendix outlines the results of Powerlink's joint planning with the Australian Energy Market Operator (AEMO) and other Network Service Providers.

C.1 Introduction

The objective of joint planning is to collaboratively identify network and non-network solutions to limitations which best serve the long-term interests of customers, irrespective of the asset boundaries (including those between jurisdictions).

The National Electricity Rules (NER) require the Transmission Annual Planning Report to outline the results of joint planning between Transmission Network Service Providers (TNSPs), including a summary of the process and outcomes of joint planning[1]. Powerlink's joint planning framework with AEMO and other Network Service Providers (NSPs) is in accordance with the requirements set out in clauses 5.14.3 and 5.14.4 of the NER.

The joint planning process results in integrated area and inter-regional strategies which optimise asset investment needs and decisions consistent with whole of life asset planning.

Joint planning begins several years in advance of an investment decision. Depending on the nature of the limitation or asset condition driver to be addressed and the complexity of the proposed corrective action, the nature and timing of future investment needs are reviewed at least on an annual basis utilising an interactive joint planning approach.

In general, joint planning seeks to:

- understand the issues faced by the different network owners and operators
- understand existing and forecast network limitations between neighbouring NSPs
- identify the most efficient options to address these issues, irrespective of the asset boundaries (including those between jurisdictions)
- influence how networks are operated and managed, and what network changes are required.

Projects where the estimated capital cost of a feasible network option is greater than $8 million are subject to a formal consultation process under the applicable regulatory investment test mechanism. The owner of the asset where the limitation emerges will determine whether a Regulatory Investment Test for Transmission (RIT-T) or Regulatory Investment Test for Distribution (RIT-D) is used to progress the investment recommendation under the joint planning framework. This provides customers, stakeholders and interested parties the opportunity to provide feedback and discuss alternative solutions to address network needs. Ultimately, this process results in investment decisions which are prudent, transparent and aligned with stakeholder expectations.

C.2 Working and regular engagement groups

Powerlink regularly undertakes joint planning meetings with AEMO, Energy Queensland (as owner of the Energex and Ergon Energy Distribution Network Service Providers (DNSPs)) and Jurisdictional Planning Bodies (JPB) from across the National Electricity Market (NEM). There are a number of working groups and reference groups which Powerlink contributes to:

- Executive Joint Planning Committee (EJPC)
- Joint Planning Committee (JPC)
- Regulatory Working Group (RWG)
- Forecasting Reference Group (FRG)
- Power System Modelling Reference Group (PSMRG)
- NEM Working Groups of Energy Networks Australia (ENA)
- General Power System Risk Review (GPSRR)[2]
- Operational Transition Points Working Group (OTPWG) and Future Transition Points Working Group (FTPWG)
- AEMO's System Security Working Group
- AEMO's Integrated System Plan (ISP) including joint planning and submissions to the ISP Inputs, Assumptions and Scenarios Report, ISP Methodology and development of ISP Preparatory Activity reports
- AEMO's System Strength Impact Assessment Guidelines and Methodology
- Queensland-New South Wales Interconnector (QNI) Test Working Group
- Transgrid when assessing the economic benefits of expanding the power transfer capability between Queensland and New South Wales (NSW)

1 National Electricity Rules, clause 5.12.2(c)(12).
2 Refer to Section 6.3.

- Energex and Ergon Energy for the purposes of efficiently planning developments and project delivery in the transmission and sub-transmission network.

C2.1 Executive Joint Planning Committee

The EJPC coordinates effective collaboration and consultation between JPBs and AEMO on electricity transmission network planning issues. The EJPC directs and coordinates the activities of the Forecasting Reference Group, and the Regulatory Working Group. These activities ensure effective consultation and coordination between JPBs, Transmission System Operators and AEMO on a broad spectrum of perspectives on network planning, forecasting, market modelling, and market regulatory matters in order to deal with the challenges of a rapidly changing energy industry.

C2.2 Joint Planning Committee

The JPC is a working committee supporting the EJPC to achieve effective collaboration, consultation and coordination between JPB, Transmission System Operators and AEMO on electricity transmission network planning issues.

C.2.3 Forecasting Reference Group

The FRG is a monthly forum of AEMO and industry forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

C.2.4 Regulatory Reference Group

The RWG is a working group to support the EJPC to achieve effective collaboration, consultation and coordination between JPBs, Transmission System Operators and AEMO on key areas related to the application of the transmission regulatory framework and suggestions for improvement.

C.2.5 Power System Modelling Reference Group

The PSMRG is a technical expert reference group which focuses on power system modelling and analysis techniques to ensure an accurate power system model is maintained for power system planning and operational analysis, establishing procedures and methodologies for power system analysis, plant commissioning and model validation.

C.2.6 Operational Transition Points Working Group

The OTPWG supports the transition toward 100% instantaneous renewable penetration. It promotes efficient sharing of information and learnings between NSPs and AEMO.

The OTPWG is to develop processes to identify and evaluate Operational Transition Points across multiple time horizons, with a specific focus on Horizon 1 (2 years ahead). The OTPWG also coordinates with the FTPWG, which focuses on Horizon 2 (2 to 5 years ahead), ensuring continuity and strategic alignment across both near-term and mid-term planning.

The working groups are to support System Security Planning and understand the range of studies, analyses, and trials needed to inform transition points. The working groups will review the Transition Plan for System Security, especially in relation to emerging operational issues that limit transmission network and renewable portfolio utilisation.

C.2.7 QNI Testing Working Group

Powerlink works closely with AEMO and Transgrid to test the interconnector capability between Queensland and New South Wales following the commissioning of the QNI Minor project by Transgrid in mid-2022. The group manages the inter-network test program for this upgrade in QNI capacity, in accordance with clause 5.7 of the NER.

C.3 AEMO Integrated System Plan

Powerlink works closely with AEMO to support the development of the ISP. The ISP sets out a roadmap for the eastern seaboard's power system over the next two decades by establishing a whole of system plan for efficient development that achieves system needs through a period of significant change.

During 2024 and 2025 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios for the 2026 ISP.

Process

Powerlink continues to provide a range of network planning inputs to AEMO's ISP consultation and modelling processes, via joint planning processes, regular engagement, workshops and through formal consultations.

Methodology

More information on the 2026 ISP, including methodology and assumptions, is available on AEMO's website.

Outcomes

The 2024 ISP identified the following actionable projects for Queensland:

- QNI Connect as an actionable project to increase transfer capacity between Queensland and New South Wales, improving reliability and market efficiency
- Gladstone Grid Reinforcement
- Central Queensland to Southern Queensland connection[3].

C.4 AEMO System Security Reports

AEMO's 2024 System Security Reports covers a 10-year outlook period from December 2024 to December 2034. It provides updated system strength requirements, inverter-based resource (IBR) forecasts, and identifies potential shortfalls across the NEM during this timeframe.

Declining minimum operational demand, changing synchronous generator behaviour and rapid uptake of variable renewable energy resources combine to present opportunities for delivery of innovative and essential power system security services.

Process

Powerlink has worked closely with AEMO to determine the system strength, inertia and Network Support and Control Ancillary Services requirements for the Queensland region. Powerlink and AEMO reviewed the Queensland fault level nodes and their minimum three phase fault levels and assessed the reactive power absorption requirements.

Methodology

AEMO applied the System Strength Requirements Methodology to determine the Queensland fault level nodes and their minimum three phase fault levels. More information on the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls is available on AEMO's **website**.

Outcomes

The 2024 System Strength Report confirmed the existing minimum fault level requirements at the Queensland system strength nodes. New system strength shortfalls of between 105 MVA and 173 MVA were identified (at Lilyvale, Greenbank and Western Downs), linked with decreased energy exports to NSW, with more energy available in that region following the delayed retirement of Eraring Power Station. That change has resulted in fewer thermal units expected to be online economically in Queensland, and lower fault levels than previously projected.

Powerlink has remediation arrangements in place to address the previous shortfall at Gin Gin node and has completed a RIT-T to meet system strength requirements across all Queensland nodes[4].

C.5 General Power System Risk Review

AEMO published the 2025 GPSRR in July 2025.

Process

In accordance with rule 5.20A of the NER, AEMO in consultation with TNSPs prepares a GPSRR for the NEM. The purpose of the GPSRR is to:

- prioritise risks comprising contingency events and other events and conditions that could lead to cascading outages or major supply disruptions
- review current arrangements for managing the identified priority risks and options for their future management
- review the arrangements for management of existing protected events and consideration of any changes or revocation
- review the performance of existing Emergency Frequency Control Schemes (EFCS) and the need for any modifications.

Methodology

With support from Powerlink, AEMO assessed the performance of existing EFCS. AEMO also assessed high priority non-credible contingency events identified in consultation with Powerlink.

Outcomes

The Final 2025 GPSRR report recommended:

- all NSPs manage risks associated with localised aggregated battery energy storage system (BESS) response to remote frequency disturbances
- governments implement regulatory frameworks for emergency backstop capability in all regions. DNSPs implement and test backstop systems, monitor compliance, and develop operating procedures. AEMO refine minimum system load (MSL) models and operational procedures for backstop activation.

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3 Refer to Section 5.3.3 for detail regarding actionable projects for Queensland in the 2024 ISP.
4 Refer to Section 3.4 for detail regarding Powerlink's System Strength RIT-T.

- governments strengthen governance frameworks for consumer energy resources (CER) technical standards and compliance enforcement. Manufacturers improve compliance and DNSPs monitor for compliance.
- AEMO is currently working on the design of a Queensland OFGS in consultation with Powerlink. The design of the Queensland OFGS scheme has been finalised and are now progressing to implementation.
- while Remedial Action Schemes (RAS) can reduce costs and defer infrastructure investment, they increase system complexity and risk of unexpected interactions. AEMO is to lead an industry-wide project to establish explicit RAS requirements in the NEM.

Carry-over recommendations from 2024 GPSRR include:

- Implementation of a Special Protection Scheme (SPS) for the loss of both Columboola to Western Downs 275kV lines. The loss of both of these lines, which supply the Surat zone, is non-credible but could cause QNI to lose stability.
- Reassess the non-credible contingencies for Central Queensland (CQ) and South Queensland (SQ) SPS settings, taking account of the revised composite and distributed energy resources load model.
- Powerlink and Energy Queensland to identify and implement measures to restore under frequency load shedding (UFLS) load, and to collaborate with AEMO on the design and implementation of remediation measures, including identifying UFLS circuits in reverse power flow.

C.6 Joint planning with Transgrid – Expanding the transmission transfer capacity between New South Wales and Queensland

QNI Connect is a proposed high-capacity transmission project between Queensland and NSW. It aims to strengthen the NEM by enabling up to 1,000 megawatts of additional transfer capacity between southern Queensland and the New England region. The project is being jointly developed by Powerlink and Transgrid, and is identified as an actionable project in the 2024 ISP.

The project may involve either a 330kV or 500kV overhead transmission line or a Virtual Transmission Line (VTL). It is subject to the RIT-T process for actionable ISP projects.

C.7 Joint planning with Energex and Ergon Energy

Powerlink, Energex and Ergon Energy, participate in regular joint planning and coordination meetings with Powerlink to assess emerging limitations, including asset condition drivers, to ensure the recommended solution is optimised for efficient expenditure outcomes. These meetings are held regularly to assess, in advance of any requirement for an investment decision by either NSP, matters that are likely to impact on the other NSP. Powerlink and the DNSPs then initiate detailed discussions around addressing emerging limitations as required. Joint planning also ensures that interface works are planned to ensure efficient delivery.

Table C.1 provides a summary of activities that are utilised in joint planning. During preparation of respective regulatory submissions, the requirement for joint planning increases significantly and the frequency of some activities reflect this.

Table C.1 Joint Planning Activities

Activity	Frequency	
	As Required	Annual
Sharing and validating information covering specific issues	Y	
Sharing updates to network data and models	Y	
Identifying emerging limitations	Y	
Developing potential credible solutions	Y	
Estimating respective network cost estimates	Y	
Developing business cases	Y	
Preparing relevant regulatory documents	Y	
Sharing information for joint planning analysis	Y	
Sharing information for respective works plans	Y	Y
Sharing planning and fault level reports		Y
Sharing information for Regulatory Information Notices		Y
Sharing updates to demand forecasts		Y
Joint planning workshops	Y	Y

C.7.1 Matters requiring joint planning

The following is a summary of projects where detailed joint planning with Energex and Ergon Energy (and other NSPs as required) has occurred since the publication of the 2024 TAPR (refer to Table C.2). There are a number of projects where Powerlink, Energex and Ergon Energy interface on delivery, changes to secondary systems or metering, and other relevant matters which are not covered in this chapter. Further information on these projects, including timing and alternative options is discussed in Chapter 5.

Table C.2 Joint Planning Project References

Project	TAPR Reference
Maintaining reliability of supply to Kamerunga and Cairns northern beaches	Section 5.5.1
Maintaining reliability of supply and addressing condition risks at Ingham South	Section 5.5.2
Maintaining reliability of supply to between Ross and Dan Gleeson	Section 5.5.2

Note:

(1) Operational works, such as Overload Management Systems, do not form part of Powerlink's capital expenditure budget

Appendix D Forecast of connection point maximum demands

This appendix provides details of Powerlink's forecast of connection point maximum demands.

D.1 Introduction

The National Electricity Rules (NER) require a Transmission Annual Planning Report (TAPR) to provide the forecast loads submitted by a Distribution Network Service Provider (DNSP) in respect of each connection point the DNSP has to a connection point in the Network Service Provider's network[1].

This requirement is discussed below and includes a description of:

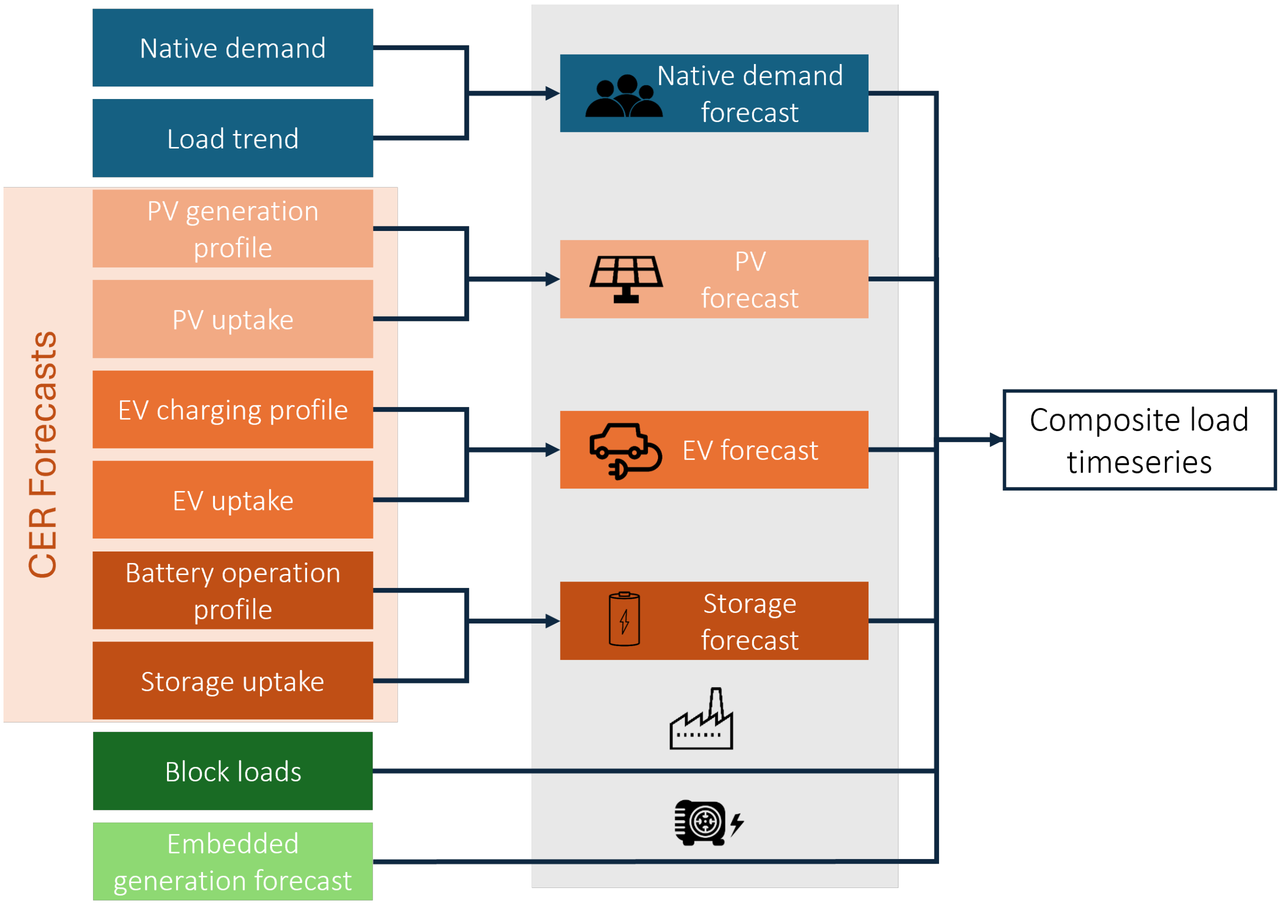
- the forecasting methodology, sources of input information and assumptions applied (refer to section D.2)
- a description of high, most likely and low growth scenarios (refer to section D.3)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR that have changed significantly from forecasts provided in the TAPR from the previous year (refer to section D.4)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR from the previous year which are significantly different from the actual outcome (refer to section D.5).

D.2 Powerlink's forecasting methodology for maximum demand

The Powerlink forecast process individually models the different component of electricity demand: Native demand, PV, EV, BESS, Block loads and Embedded Generation. It incorporates the latest assumptions for macro-economic factors and evolving trends in energy consumption and technology adoption, from sources including the Australian Bureau of Statistics (ABS), Queensland Government, the Australian Energy Market Operator (AEMO), Deloitte Access Economics economic forecasts, CSIRO GenCost reports, and internal data from Energy Queensland and Powerlink.

The following sections provide a high-level overview of each sub model and the forecast process.

Figure D.1 Schematic of the building blocks of the forecast.



1 National Electricity Rules (NER), clauses 5.12.2(c)(1) and 5.11.1, and schedule 5.7.

Independent sub models are derived for the different CER technologies, native demand, trends, block loads and embedded generation. Composite load traces are constructed from the output of each sub model and used in a Monte-Carlo process to estimate Maximum Demand with PoE 10% and 50%.

D.2.1 Native Demand Model – water and calendar sensitivity

A demand model is used to estimate a probability distribution of demand conditional on weather and calendar conditions. The demand model is trained on the past 4 years of actual metered data (at half-hourly granularity) and leverages weather data sourced from the European Centre for Medium-Range Weather Forecasts (ECMWF) Copernicus Climate Change Service's ERA5 dataset. The model allows to sample a full year of demand data, at half hourly granularity, for a given 'weather year', which is a realisation of past weather conditions.

D.2.2 Load trends

The forecasting tool uses a regression model for average demand, incorporating historical population, Gross State Product (GSP), electricity prices, energy efficiency numbers from the ABS, Queensland Government and AEMO, as well as cooling degree days and heating degree days. The trend is forecast for each scenario, with different assumptions made for these macro drivers. The tool then applies a weighted trend for each asset in Powerlink's network, based on a spatial forecast of population (at SA2 level from Queensland Government data) and the consumption split between residential, commercial and industrial customers (informed by Energy Queensland and Powerlink).

D.2.3 Consumer Energy Resource uptakes (developed with Energy Queensland)

Consumer Energy Resource (CER) forecasts are developed from bottom-up (from feeders) and top-down (at the Energex and Ergon Energy network level) process. The bottom-up forecast uses spatially granular information, and a top-down forecast captures macroeconomic and technology factors. It is then mapped and aggregated to Energy Queensland's zone substations and then to Powerlink's substations.

The bottom-up forecast is a technology adoption model, using historical technology stock (CER register for solar photovoltaic (PV) and electric vehicle (EV), vehicle registration data for EV), as well as SA2 level ABS data. It defines per feeder s-curves of technology adoption.

The top-down forecast defines an adoption curve using historical and future GSP, population and technology prices.

A reconciliation process ensures that the top-down forecast is spatially consistent with the bottom-up forecast.

D.2.4 CER profiles (developed with Energy Queensland)

The load profiles derived for EV charging are modelled through simulation of driving and charging for different vehicle types. The simulation leverages vehicle driving data sourced by Energy Queensland. The simulations provide different profiles for collaborative and convenience charging. The scenarios further define a glide path between the two types of charging to model changing patterns over the forecast horizon.

Load profiles are derived for Battery Energy Storage Systems (BESS) through:

- A simulation process for 'solar soaking' patterns
- An optimisation of the battery dispatch for customers with fixed tariffs
- An optimisation of the battery dispatch in the National Electricity Market (NEM) for systems operating in the wholesale electricity market, using historical prices in the NEM
- Similar to EVs, for each forecast scenario, a glide path between the different consumption patterns combines a nominal composite profile for BESS operation, evolving over the forecast horizon.

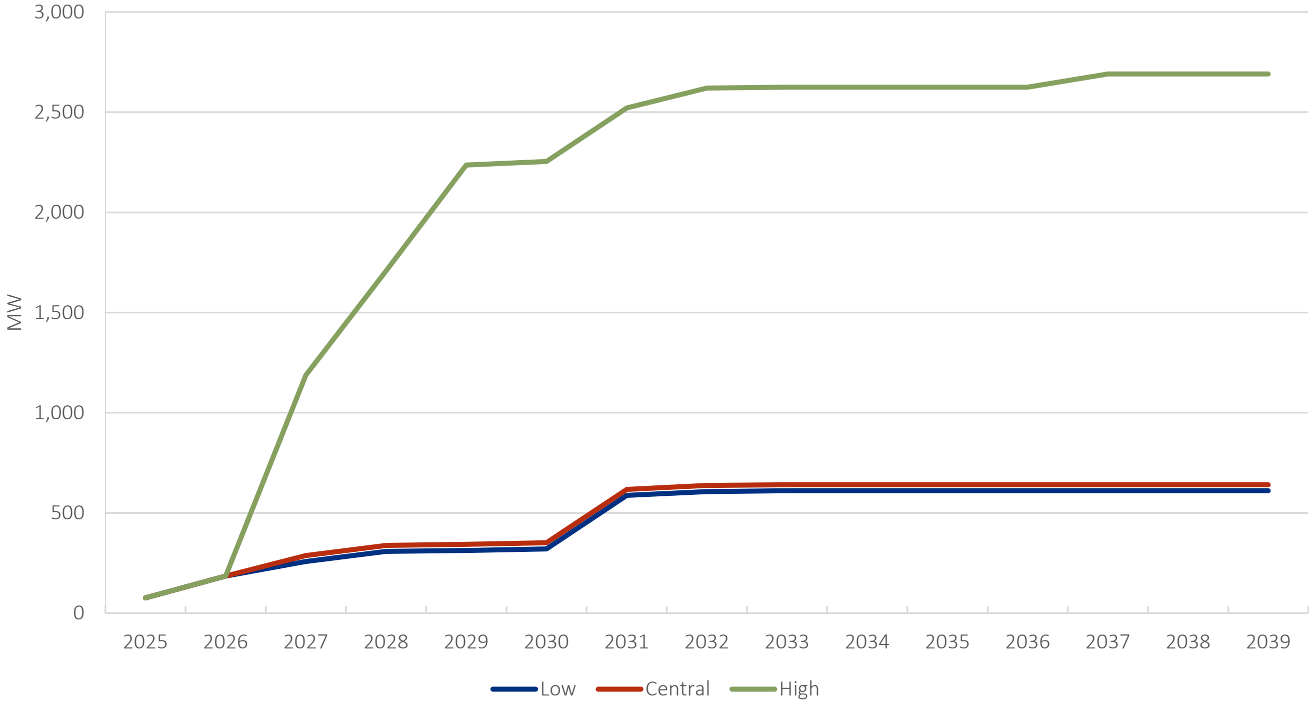
Estimates for PV generation profiles use local historical weather conditions on each network asset.

D.2.5 Block loads

Energy Queensland provide a list of block loads that are added to the relevant High, Central and Low scenarios based on consultations with their customers. Block loads are defined by their capacity as well as by a profile archetype, from which the forecast tool derives a modelled timeseries.

There are three categories of block loads: proposed, anticipated and committed. Proposed loads are all new load connections that are in the connection process and are all included in the high scenario. Anticipated loads are projects that have a high likelihood of becoming committed but do not have a signed connection and access agreement. Anticipated and committed projects are included in the Central scenario. The low scenario only includes committed loads.

Figure D.2 Block loads



D.2.6 Generator Model

Embedded generators are modelled according to their types:

- Non-dispatchable renewable generation (PV and wind) are modelled according to their capacity and historical weather conditions on site
- Dispatchable generation is modelled through profile archetypes derived from historical meter data.

D.2.7 Forecast process

The above sub-models are combined to estimate POE forecast by a Monte-Carlo approach:

- For 10 Weather Years, n estimates of demand are sampled from the modelled probability distribution (native demand model): each sample is a full year worth of load (30-minute interval)
- The samples are scaled by the trend modelled (energy consumption trend model)
- The CER profiles are multiplied by their forecast uptakes and are added to the timeseries (CER model)
- Block loads, with capacity and profiles defined by Powerlink, are added to the timeseries
- The generation is added to the timeseries (for a forecast of delivered demand)
- The Maximum demand of each composite sample is recorded
- VISION derives the 50% and 10% POE maximum demand from these 10 x n samples of maximum demand.

D.3 Description of Powerlink's High, Central and Low growth scenarios for maximum demand

The scenarios developed for the high, central and low growth scenarios were prepared in June 2025 based on the latest information. The assumptions for the Powerlink forecast of demand are consistent with the assumptions for the DER forecast developed with Energy Queensland.

D.3.1 High growth scenario assumptions for maximum demand

- GSP – High growth, averaging 2.8% per annum in the forecast horizon
- Queensland regional population growth – High growth, averaging 1.8% per annum in the forecast horizon. Refer to Figure D.7
- Electricity Prices – Decreasing prices until 2032, increasing afterwards by an average of 1.5%
- Energy efficiency – AEMO's Progressive Change scenario (2025)

- EV price parity reached in 2027, share of collaborating charging growing from 10% to 50% by 2036
- Battery charging profiles – Fast increasing participation in VPP programs, from AEMO's Green Energy Exports scenario (2025), increasing from 15% to 65% in 2049, stable after 2049
- PV prices – CSIRO Global NZE by 2050 scenario (GenCost 2024-2025), rebased on historical retail prices.

D.3.2 Central scenario assumptions for maximum demand

- GSP – Medium growth, averaging 2% per annum in the forecast horizon
- Queensland regional population growth – Medium growth, decreasing to 1.6% per annum in the forecast horizon. Refer to Figure D.7
- Electricity prices – Decreasing prices until 2027, followed by an increase at 0.7% per annum
- Energy efficiency – AEMO's Step Change scenario (2023)
- EV price parity reached in 2030, share of collaborating charging growing from 8% to 40% by 2036
- Battery charging profiles – Increasing participation in VPP programs, from 17% to 55% in 2037
- PV prices – CSIRO Current Policies scenario (GenCost 2023), rebased on historical retail prices.

D.3.3 Low scenario assumptions for maximum demand

- GSP – Slow growth, averaging 1.2% per annum in the forecast horizon
- Queensland regional population growth – Slow growth, decreasing from current levels to 1% per annum over the forecast horizon. Refer to Figure D.7
- Electricity prices – Decreasing prices until 2027, followed by a faster increase at 1.4 % per annum
- Energy efficiency – AEMO's Progressive change scenario (2023)
- EV price parity reached in 2033, share of collaborating charging growing from 5% to 15% by 2036
- Battery charging profiles – Low participation in VPP programs, increasing from 5% to 12% in 2037
- PV prices – CSIRO Global NZE post 2050 scenario (GenCost 2023), rebased on historical retail prices.

Figure D.3 Embedded Battery Energy Storage System – Capacity

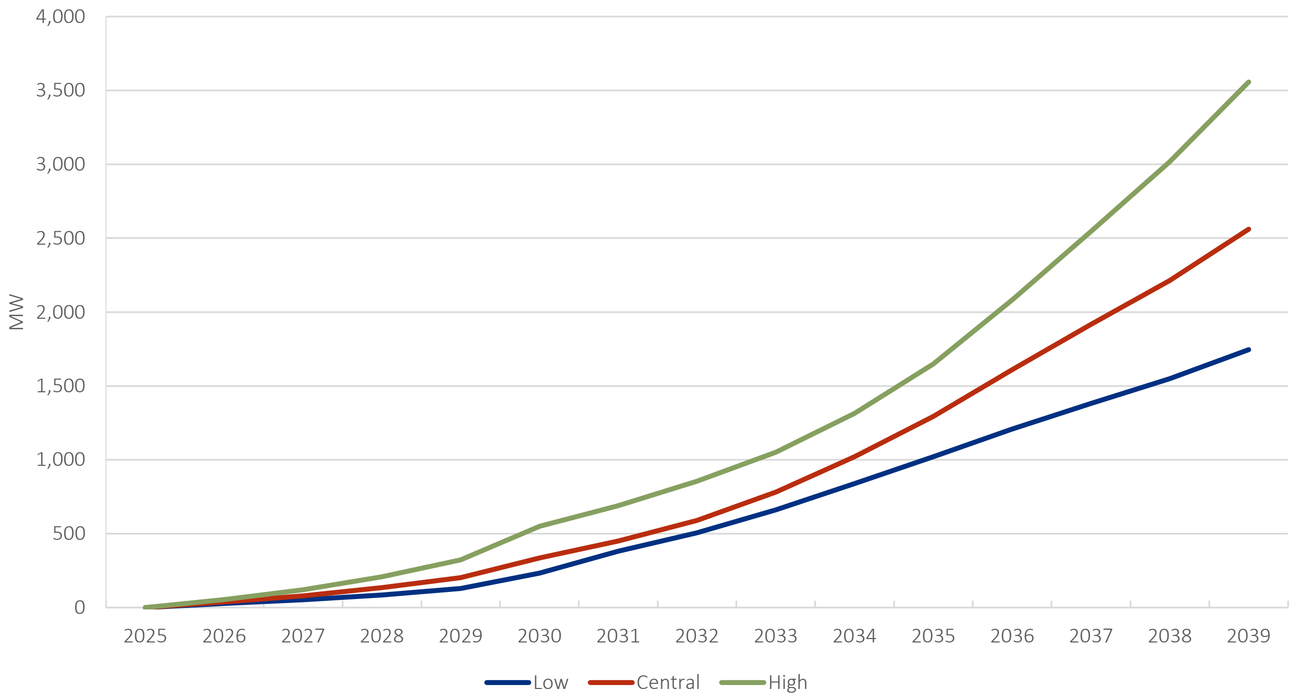


Figure D.4 Embedded Battery Energy Storage System – Energy

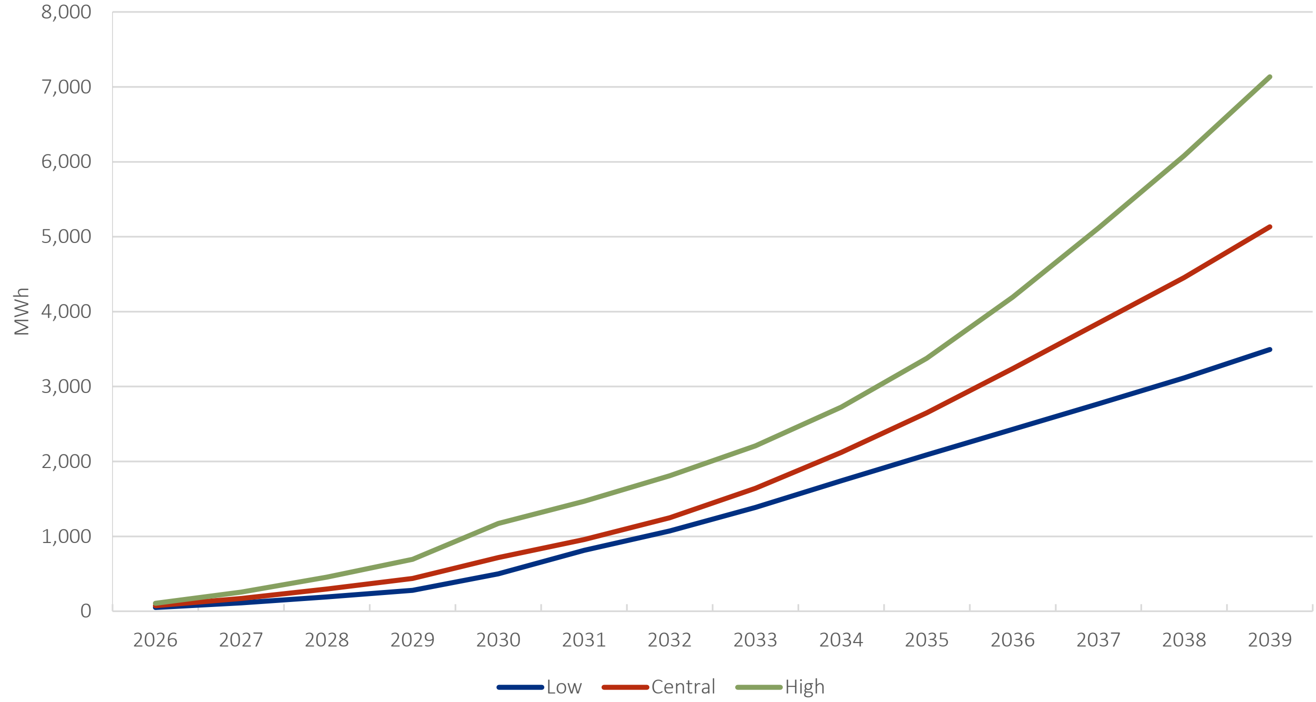


Figure D.5 Rooftop PV uptake – Capacity

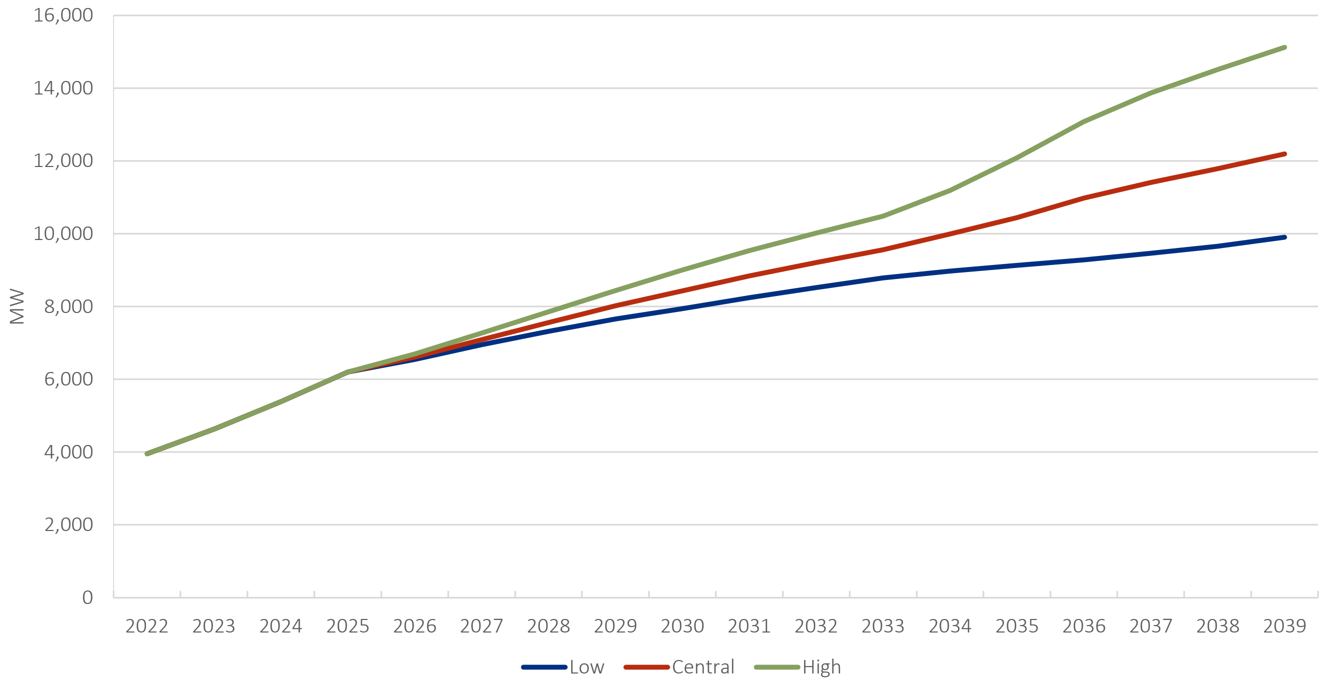


Figure D.6 Electric Vehicle uptake

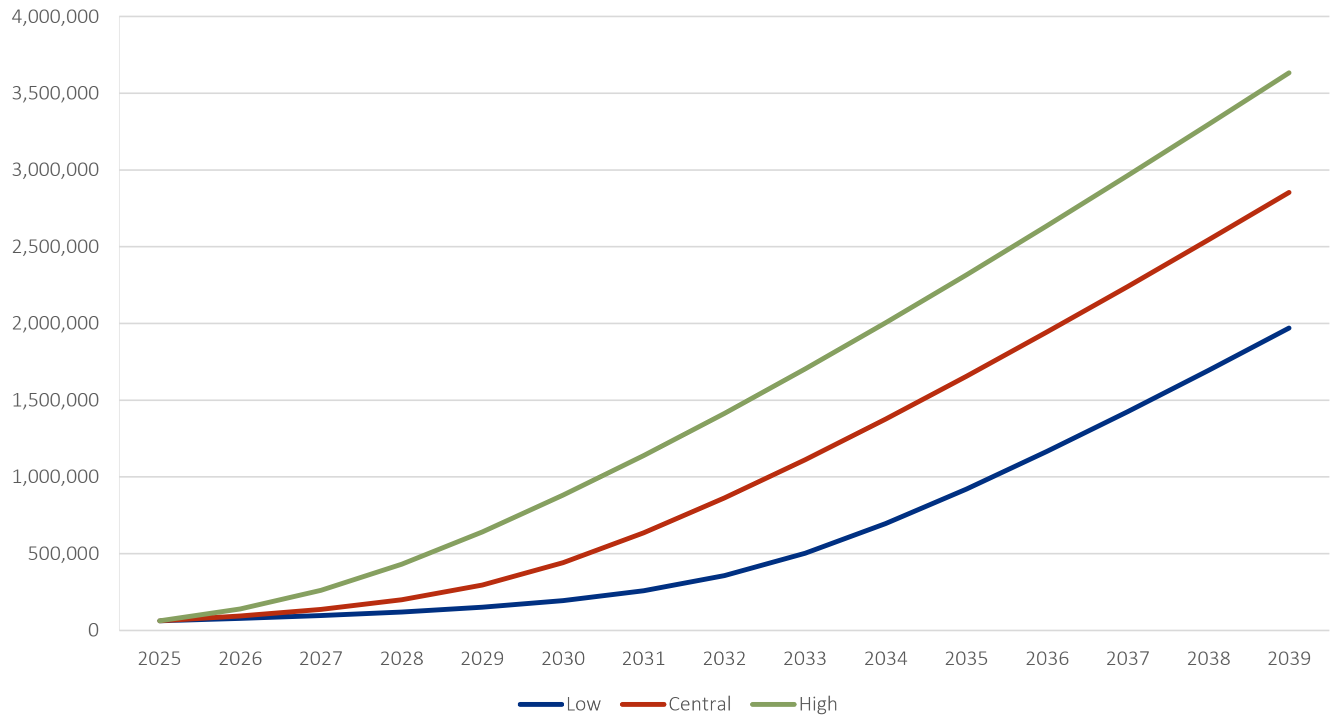
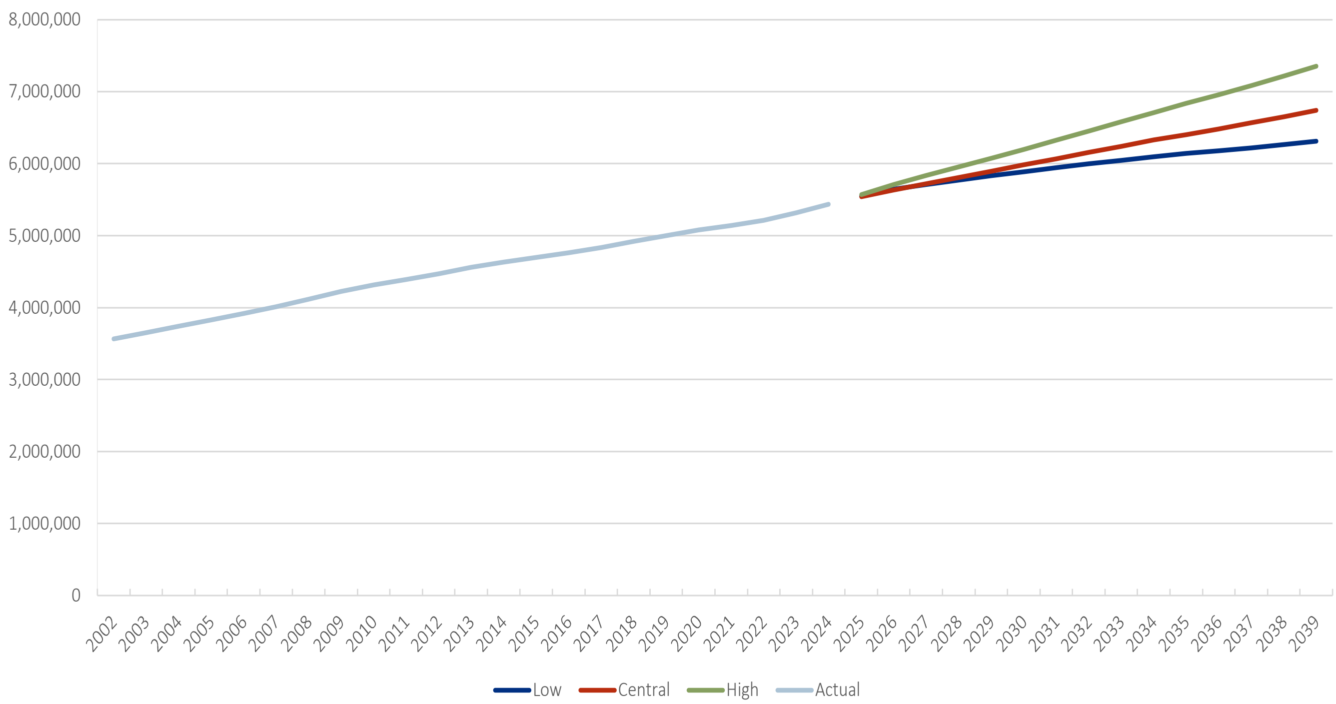


Figure D.7 Population



D.4 Significant changes to the connection point maximum demand forecasts

Major differences between the 2025 forecast and the 2024 forecast can generally be attributed to natural variation in peaks below the connection point level, which can result in displaying an associated variation in year on year changes at the connection point level, and with changes in the growth in the lower levels of the network rather than from any network configuration changes or significant block loads. Changes in proposed block loads also account for differences. These, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

Table D.1 Ergon connection points with the greatest difference in growth between the 2025 and 2024 forecasts

Connection Point	kV	Change in growth rate
Blackwater	132	89%
Woree (Cairns North)	132	78%
Turkinje (Craiglie and Lakeland)	132	34%
Oakey	110	16%
Dysart	66	-18%
Columboola	132	-18%

Table D.2 Energex connection points with the greatest difference in growth between the 2025 and 2024 forecasts

Connection Point	kV	Change in growth rate
Abermain	110	-30%

D.5 Significant differences to actual observations

The 2024/25 summer was relatively hotter across large parts of Queensland when compared to recent seasons.

This, combined with natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2024 forecast values for 2024/25 and what was observed.

Table D.3 Ergon connection points with greater than 10% absolute difference and >= 10 MW difference between the peak 2024/25 and corresponding base 2024 forecast for 2024/25.

Connection Point	2024/25 forecast peak	2024/25 actual	Difference
Oakey	21	37	45%
Woree (Cairns North)	54	96	43%
Gladstone South	44	62	28%
Lilyvale (Barcaldine & Clermont)	43	60	28%
Middle Ridge	245	284	14%
Gin Gin	176	196	10%
Moranbah	137	120	-15%
Columboola	102	88	-16%
Turkinje	70	56	-25%
Garbutt	103	78	-32%
Newlands	29	12	-148%

Table D.4 Energex connection points with the greater than 10% absolute difference and >= 10 MW difference between the peak 2024/25 and corresponding base 2024 forecast for 2024/25

Connection Point	2024/25 forecast peak	2024/25 actual	Difference
Abermain	97	72	-34%
Woolooga (Gympie)	234	261	10%
Molendinar	578	650	11%
Rocklea	145	166	13%
Loganlea	450	523	14%
Middle Ridge (Postmans Ridge and Gatton)	99	117	15%

D.6 Customer forecasts of connection point maximum demands

Tables D.1 to D.18 (in the Appendix D Compendium on Powerlink's website) show 10-year forecasts of native summer and winter demand at connection point peak, for High, Central and Low growth scenarios (refer to Appendix D. These forecasts have been supplied by Powerlink direct connect customers and have been produced by Powerlink.

The connection point reactive power (MVAr) forecast includes the effect of customer's downstream capacitive compensation.

Groupings (sums of non-coincident forecasts) of some connection points are used to protect the confidentiality of specific customer loads.

In Tables D.1 to D.18 the zones in which connection points are located are abbreviated as follows:

FN	Far North zone
R	Ross zone
NW	North West zone
N	North zone
CW	Central West zone
G	Gladstone zone
WB	Wide Bay zone
S	Surat zone
B	Bulli zone
SW	South West zone
M	Moreton zone
GC	Gold Coast zone

Appendix E Possible network investments for the 10-year outlook period

This appendix summarises possible network investments for the 10-year outlook period.

Through the annual planning review, Powerlink has identified that the investments listed in this appendix are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the 10-year outlook period. Potential projects have been grouped by region and zone as described in Chapter 5. It should be noted that the indicative cost of potential projects also excludes known and unknown contingencies.

As required by the Australian Energy Regulator's Transmission Annual Planning Report Guidelines, additional information on these potential projects is available in the TAPR Templates which can be accessed through Powerlink's TAPR Portal. Where appropriate, the technical envelope for potential non-network solutions has been included in the relevant table.

Potential condition-based programs of work are listed in Table 5.10.

E.1 Northern Region

E.1.1 Far North zone

Table E.1 Possible network investments in the Far North zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Joint Regulatory Investment Test for Transmission with Ergon Energy					
Rebuild the 132kV transmission line between Woree and Kamerunga substations and Kamerunga 132kV Substation rebuild (1)	New 132kV double circuit transmission line, substation establishment on a new site and associated Ergon 22kV works	Maintain supply reliability to the Far North zone	December 2028	Two 132kV single circuit transmission lines, substation establishment on a new site and associated Ergon 22kV works (2)	$201m (3)
Transmission lines					
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations	Staged line refit works on steel lattice structures	Maintain supply reliability to the Far North and Ross zones	Staged works by June 2031 (4)	New transmission line (2)	$39m (5)
Line refit works on the 132kV transmission line between Chalumbin and Turkinje substations (5)	Refit of the Chalumbin to Turkinje 132kV transmission line	Maintain supply reliability to Turkinje area	December 2033 (3)	Establishment of 275/132kV switching substation near Turkinje including two transformers	$21m (4)
Substations					
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2028	Life extension of the existing transformer or a non-network alternative of up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully	$9m
Edmonton 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2033 (4)	Selected replacement of 132kV secondary systems	$9m

Table E.1 Possible network investments in the Far North zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2036 (4)	Selected replacement of 132kV secondary systems	$3m
Chalumbin 275kV Substation reinvestment	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Far North zone	June 2031 (4)	Full replacement of all 275kV and 132kV primary plant and secondary systems	$58m (5)
Woree PASS M1 replacement	Replacement of PASS M1 unit of reactors	Maintain supply reliability to the Far North zone	June 2028	Replacement of PASS M1 units as dead tank circuit breakers	$9m
Woree 275kV and 132kV secondary systems replacement	Selected replacement of 275kV and 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2033	Full replacement of 275kV and 132kV secondary systems	$12m (5)
El Arish 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2036 (4)	Full replacement of 275kV and 132kV secondary systems	$10m

Notes:

(1) The template data for the transmission line and substation investments are identified separately in the TAPR portal.

(2) The envelope for non-network solutions is defined in Section 5.5.1.

(3) Reflects the estimated costs in the Project Specification Consultation Report. Powerlink and Ergon Energy are progressing the development of the Project Assessment Draft Report at the time of 2025 TAPR publication.

(4) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(5) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(6) Compared to the 2024 TAPR, the potential project (proposed network solution) has been updated to reflect the result of the most recent planning analysis (refer to Section 5.5.1).

E.1.2 Ross zone

Table E.2 Possible network investments in the Ross zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Ross and Dan Gleeson substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2031 (1)	New 132kV transmission line (2)	$12m (2)
Substations					
Ingham South 132kV Substation reinvestment	Full replacement of 132kV primary plant and secondary systems	Maintain supply reliability to the Ross zone	December 2028 (1)	Selected replacement of 132kV primary plant and secondary systems (3)	$26m
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2029 (1)	Selected replacement of 132kV secondary systems (2)	$13m (2)
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2028 (1)	Full replacement of 132kV secondary systems (2)	$26m (3)
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2028 (1)	Full replacement of secondary systems (2)	$10m
Townsville South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2028 (1)	Full replacement of 132kV secondary systems (2)	$11m
Yabulu South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034	Full replacement of 132kV secondary systems	$13m
Clare South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2036 (1)	Full replacement of 132kV secondary systems	$14m
Ross 275kV reactor bushing replacement	Replacement of bushing on one of the 275kV reactors	Maintain supply reliability to the Ross zone	June 2033	Replacement of 275kV reactor	$4m

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(3) The envelope for non-network solutions is defined in this Section 5.5.2.

E.1.3 North zone

Table E.3 Possible network investments in the North zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Collinsville North, Strathmore and Clare South substations	Line refit works on the 132kV transmission line	Maintain supply reliability to the North zone	June 2035	Rebuild of the 132kV transmission line between Collinsville North, Strathmore and Clare South substations	$44m
Substations					
Alligator Creek 132kV Substation reinvestment	Selected replacement of 132kV primary plant and SVC secondary systems replacement	Maintain supply reliability to the North zone	December 2030 (1)	Full replacement of 132kV primary plant and SVC secondary systems replacement	$34m (2)
Oonooie Substation reinvestment	Selected replacement of 132kV primary plant, replacement of 132kV secondary systems and SVC	Maintain supply reliability to Oonooie	June 2030	Replacement of all 132kV primary plant and secondary systems and SVC	TBC (3)
Life extension of 132/69/11kV transformer at Newlands Substation	10-year life extension of 132/69/11kV transformer	Maintain supply reliability to the North zone	December 2028	Replacement of 132/69/11kV transformer	$3m
North Goonyella 132kV secondary systems replacement	Selected replacement of 132kV secondary systems in the existing building	Maintain supply reliability to the North zone	December 2027	Replacement of 132kV secondary systems in a new building	$9m (2)
Coppabella 132kV Substation reinvestment	Replacement of all 132kV primary plant and secondary systems and SVC	Maintain supply reliability to Coppabella	June 2029	Replacement of all 132kV primary plant and secondary systems and SVC	TBC (3)
Pioneer Valley 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2035	Full replacement of 132kV primary plant	$3m
Strathmore SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability to the North zone	June 2028 (1)	Staged replacement of secondary systems (4)	$24m (2)
Strathmore 275kV and 132kV secondary systems replacement	Selected replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the North zone	June 2034	Selected replacement of 275kV and 132kV secondary systems in existing panels	$15m
Nebo 275kV line reactor replacement	Replacement of 275kV line reactor	Maintain supply reliability to the North zone	June 2032	Life extension of the 275kV line reactor	$10m
Wandoo 132kV Substation reinvestment	Selected replacement of 132kV primary plant and full replacement of 132kV secondary systems	Maintain supply reliability to Wandoo	December 2029	Replacement of 132kV primary plant and 132kV secondary systems	TBC (3)

Notes:

(1) The revised timing from the 2024 TAPR is based upon the latest condition assessment.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

(3) To be confirmed. Powerlink is continuing to work with affected customers to determine the detailed scope of works required.

(4) The envelope for non-network solutions is defined in Section 5.5.3.

E.2 Central Region

E.2.1 Central West zone

Table E.4 Possible network investments in the Central West zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Line refit works on the 275kV transmission line between Bouldercombe and Broadsound substations	Line refit works on the 275kV transmission line	Maintain reliability in the Central West zone	December 2035	Rebuild the 275kV transmission line between Bouldercombe and Broadsound substation	$6m
Line reinvestment on the 275kV transmission line between Bouldercombe and Nebo substations	Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations	Maintain supply reliability in the Central West zone and Northern region	December 2032 (1)	Stanwell to Broadsound second side stringing New 275kV transmission line between Bouldercombe and Broadsound substation	$41m (2)
Line refit works on the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations	Line refit works on the 132kV transmission line	Maintain supply reliability in the Central West zone	June 2035	Rebuild the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations	$58m
Line refit works on the 132kV transmission line between Moranbah, Kemmis and Nebo substations	Line refit works on the 132kV transmission line	Maintain supply reliability in the Central West zone and Northern region	June 2035	Rebuild the 132kV transmission line between Moranbah, Kemmis and Nebo substations	$40m
Substations					
Blackwater selected 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Central West zone	June 2029 (1)	Full replacement of 132kV primary plant	$28m (2)
Biloela 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Central West zone	December 2033	Full replacement of 132kV secondary systems	$21m (2)
Moura 132/22kV transformer replacements	Replacement of 132/22kV transformers	Maintain supply reliability to the Central West zone	June 2032	Refit of 132/22kV transformers	$11m
Broadsound 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability to the Central West zone	June 2035 (1)	Full replacement of 275kV secondary systems	$10m
Broadsound 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	June 2030 (1)	Full replacement of 275kV primary plant (2)	$19m
Norwich Park 132kV Substation reinvestment	Selected replacement of 132kV primary plant and replacement of 132kV secondary systems	Maintain supply reliability to Norwich Park	June 2033	Replacement of all 132kV primary plant and secondary systems	TBC (3)
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2036 (1)	Full replacement of 132kV secondary systems	$5m

Table E.4 Possible network investments in the Central West zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Calvale 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	June 2031 (1)	Full replacement of 275kV primary plant (2)	$39m (2)
Grantleigh 132kV Substation reinvestment	Selected replacement of 132kV primary plant and replacement of 132kV secondary systems and SVC	Maintain supply reliability to Grantleigh	December 2030	Replacement of all 132kV primary plant and secondary systems and SVC	TBC (3)
Blackwater 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2033	Full replacement of 132kV secondary systems	$19m
Stanwell 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central west zone and Northern region	June 2034	Full replacement of 275kV primary plant	$22m

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

(3) To be confirmed. Powerlink is continuing to work with affected customers to determine the detailed scope of works required.

E.2.2 Gladstone zone

Table E.5 Possible network investments in the Gladstone zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Reinvestment in the 132kV transmission line between Gladstone Power Station and Callemondah Substation	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	June 2035	Rebuild the 132kV transmission line between Gladstone Power Station and Callemondah Substation	$7m
Substations					
Callemondah Substation reinvestment	Selected replacement of 132kV primary plant and secondary systems	Maintain supply reliability to Callemondah	June 2029 (1)	Full replacement of 132kV primary plant and secondary systems	$29m (2)
Rockhampton 132kV primary plant and secondary systems replacement	Selected replacement of 132kV primary plant and secondary systems	Maintain reliability in Rockhampton	June 2033 (1)	Full replacement of 132kV primary plant and secondary systems	$11m (2)
Pandoin 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2036 (1)	Selected replacement of 132kV secondary systems	$6m
Wurdong 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability in the Gladstone zone	June 2035 (1)	Full replacement of 275kV primary plant	$31m (2)

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

E.3 Southern Region

E.3.1 Wide Bay zone

Table E.6 Possible network investments in the Wide Bay zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Rebuild of the 275kV transmission line between Calliope River Substation and the Wurdong Tee	New double circuit transmission line for the first 15km out of Calliope River substation	Maintain supply reliability to the CQ-SQ transmission corridor (and Gladstone zone)	December 2035 (1)	Refit the two single circuit 275kV transmission lines	$100m (2)
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Substation	Refit the single circuit 275kV transmission line between Calliope River Substation and Wurdong Substation	Maintain supply reliability to the CQ-SQ transmission corridor (and Gladstone zone)	June 2033 (1)	Rebuild the 275kV transmission line as a double circuit	$33m (2)
CQ-SQ coastal feeder uprating	Increase the MVA capacity of the coastal feeders to allow a higher line rating	Maintain supply reliability to the CQ-SQ transmission corridor	June 2031	Rebuild the 275kV coastal transmission line between CQ-SQ	$20m
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	Refit the 275kV transmission line between Woolooga and South Pine substations	Maintain supply reliability to the Moreton zone	June 2032 (1)	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$47m (2)
Targeted reinvestment in the 275kV transmission lines between Wurdong Tee and Gin Gin Substation	Refit the 275kV transmission line between Wurdong Tee and Gin Gin Substation	Maintain supply to the Wide Bay zone	December 2034 (1)	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$91m (2)
Line refit works on the 275kV transmission line between Woolooga and Teebar Creek substations	Refit the 275kV transmission line between Woolooga and Teebar Creek substations	Maintain supply to the Wide Bay zone	June 2034	Rebuild the 275kV transmission line between Woolooga and Teebar Creek substations	$14m
Substations					
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2034 (1)	Selected replacement of 132kV and 275kV secondary systems	$39m (2)
Woolooga 132kV selected primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply to the Wide Bay zone	June 2033 (1)	Full replacement of 132kV secondary systems	$9m
Woolooga 275kV and 132kV secondary systems replacement	Full replacement of 275kV and 132kV secondary systems.	Maintain supply to the Wide Bay zone	June 2035 (1)	Selected replacement of 275kV, 132kV and SVC secondary systems	$65m (2)
Palmwoods 275kV and 132kV selected primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Wide Bay zone	June 2034 (1)	Full replacement of 275kV and 132kV primary plant	$18m (1)

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

E.3.2 Surat zone

Table E.7 Possible network investments in the Surat zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Columboola 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Surat zone	June 2036 (1)	Full replacement of secondary systems	$17m

Note:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

E.3.3 Bulli zone

Table E.8 Possible network investments in the Bulli zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Millmerran 330kV AIS secondary systems replacement	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	December 2035 (1)	Full replacement of secondary systems	$14m (2)
Braemar 330kV secondary systems replacement non-iPASS	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	June 2034	Full replacement of secondary systems	$23m

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

E.3.4 South West zone

Table E.9 Possible network investments in the South West zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Middle Ridge 275kV and 110kV secondary systems replacement	Selected replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the South West zone	June 2031 (1)	Full replacement of 275kV and 110kV secondary systems	$63m (3)
Middle Ridge 275/110kV transformers life extension	Life extension of transformers 2 and 3	Maintain supply reliability in the South West zone	December 2032	Replacement of transformers 2 and 3 (2)	$6m
Middle Ridge 110kV primary plant replacement	Selected replacement of selected 110kV primary plant	Maintain reliability of supply in the South West zone	December 2033 (1)	Full replacement of 110kV primary plant	$15m (3)

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 5.7.4.

(3) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

E.3.5 Moreton zone

Table E.10 Possible network investments in the Moreton zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	Replace the 110kV underground cable between Upper Kedron and Ashgrove West substations using an alternate easement	Maintain supply reliability in the Moreton zone	June 2031 (1)	In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (2)	$53m (3)
Rearrangement of the 275kV feeder between Blackwall Substation and Karana Downs	275kV feeder rearrangement to enable construction of 4km of 275kV transmission line	Maintain supply reliability in the Moreton zone	December 2033	New 275kV double circuit line from Blackwall to South Pine	$10m
Substations					
South Pine 275/110kV transformer replacement	Replacement of 275/110kV transformer	Maintain supply reliability in the Moreton zone	June 2030	Retirement of a single 275kV/110kV transformer with non-network support (2)	$16m
South Pine 110kV secondary systems replacement	In-situ replacement of 110kV secondary systems in existing buildings	Maintain supply reliability in the Moreton zone	June 2031	Full replacement of 110kV secondary systems and buildings	$38m
South Pine SVC secondary systems and 275kV secondary replacement	Replacement of the existing secondary systems and associated control systems for the SVC and upfront replacement of the 275kV secondary systems	Maintain supply reliability in the Moreton zone	June 2031	Full replacement of the SVC and staged replacement of the 275kV secondary systems	$58m
South Pine 275kV primary plant replacement	Staged replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2033 (1)	Full replacement of 275kV primary plant	$42m (3)
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2029 (1)	Staged replacement of 110kV secondary systems (2)	$25m (3)
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2033 (1)	Selected replacement of 110kV secondary systems (2)	$56m
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2035 (1)	Staged replacement of 110kV secondary systems	$31m (3)
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2035	Staged replacement of 110kV secondary systems	$17m (3)
Tennyson 110/33kV transformer replacement	Replacement of 110/33kV transformer	Maintain supply reliability in the Moreton zone	June 2028	Refit of the 110/33kV transformer (2)	$11m

Table E.10 Possible network investments in the Moreton zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2030 (1)	Staged replacement of 275kV and 110kV secondary systems (2)	$39m (3)
West Darra 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2032 (1)	Staged replacement of 110kV secondary systems	$12m
Loganlea 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2033 (1)	Staged replacement of 275kV primary plant	$5m
Loganlea 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton zone	December 2034	Selective replacement of 275kV secondary systems	$28m
Greenbank SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	June 2030 (1)	Staged replacement of SVC secondary systems (2)	$26m (3)
Mount England 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	December 2033 (1)	Staged replacement of 275kV secondary systems and primary plant	$5m (3)
Belmont 110kV and 275kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 275kV and 110kV secondary systems	$24m
Abermain 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2036 (1)	Staged replacement of 275kV and 110kV secondary systems	$10m (3)
Abermain 275kV and 110kV primary plant replacement	Selected 275kV and 110kV primary plant replacement	Maintain supply reliability in the Moreton zone	June 2033 (1)	Full replacement of 275kV and 110kV primary plant	$8m
Greenbank 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	June 2034	Staged replacement of 275kV secondary systems	$71m (3)

Notes:

(1) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 5.7.5.

(3) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

E.3.6 Gold Coast zone

Table E.11 Possible network investments in the Gold Coast zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 110kV transmission line between Mudgeeraba Substation and Terranora	Targeted line refit works on steel lattice structures	Maintain supply reliability from Queensland to NSW Interconnector	June 2031 (1)	Full line refit New transmission line (2)	$8m (3)
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2031 (1)	Selected replacement of 275kV secondary systems (2)	$53m (3)
Mudgeeraba 110kV primary plant and secondary systems replacement	Selected replacement of 110kV primary plant and staged replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2031 (1)	Full replacement of 110kV secondary systems and replacement of the transformer	$51m (3)

Notes:

(1) The envelope for non-network solutions is defined in Section 5.7.6.

(2) The change in timing of the network solution from the 2024 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2024 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

Appendix F TAPR templates methodology

This appendix provides information about Powerlink's Transmission Annual Planning Report Templates.

The National Electricity Rules (NER) require a Transmission Annual Planning Report (TAPR) to be consistent with the Australian Energy Regulator's (AER's) Transmission Annual Planning Report Guidelines (TAPR Guidelines)[1]. The TAPR Guidelines set out the required format of TAPRs, including the provision of TAPR Templates to complement the TAPR document. The purpose of the TAPR Templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are strongly encouraged to contact Powerlink in the first instance.

The TAPR template data may be directly accessed on Powerlink's TAPR Portal. Alternatively, contact NetworkAssessments@powerlink.com.au for assistance.

F.1 Context

While care is taken in the preparation of TAPR Templates, data is provided in good faith. Powerlink accepts no responsibility or liability for any loss or damage that may be incurred by persons acting in reliance on this information or assumptions drawn from it.

The proposed preferred investment and associated data is indicative, has the potential to change and will be technically and economically assessed under the Regulatory Investment Test for Transmission (RIT-T) consultation process as/if required at the appropriate time. TAPR Templates may be updated at the time of RIT-T commencement to reflect the most recent data and to better inform non-network providers[2]. Changes may also be driven by the external environment, advances in technology, non-network solutions and outcomes of other RIT-T consultations which have the potential to shape the way in which the transmission network develops.

There is likely to be more certainty in the need to reinvest in key areas of the transmission network which have been identified in the TAPR in the near-term, as assets approach their anticipated end of technical service life. However, the potential preferred investments (and alternative options) identified in the TAPR Templates undergo detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to deliver greater benefits to customers through improving and further refining options. In the medium to long-term, there is less certainty regarding the needs or drivers for reinvestments. As a result, considerations in the latter period of the annual planning review require more flexibility and have a greater potential to change or adapt to the external environment as the NEM evolves and customer behaviour changes.

Where an investment is primarily focused on addressing asset condition issues, Powerlink has not attempted to quantify the impact on the market; for example, where there are market constraints arising from reconfiguration of the network around the investment and Powerlink considers that generation operating within the market can address this constraint.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

F.2 Methodology/principles applied

The TAPR Guidelines incorporate text to define or explain the different data fields in the template. Powerlink has used these definitions in the preparation of the data within the templates.

For connection point templates, the expected unserved energy (EUSE) has been calculated using aggregated failure statistics for network assets, considering both momentary and sustained failures by the following expression:

EUSE = Probability of Asset Failure × Median Restoration time × MW @ Risk

For line segment templates, the expected unserved energy should be interpreted as the annual energy that cannot be supplied by that asset under system normal conditions.

Further to the AER's data field definitions, Powerlink provides details on the methodology used to forecast the daily demand profiles. Table F.1 provides further context for some specific data fields.

The data fields are denoted by their respective TAPR Guideline Rule designation, TGCPXXX (TAPR Guideline Connection Point) and TGTLXXX (TAPR Guideline Transmission Line).

1 National Electricity Rules, clause 5.12.2(c)(1). See also Australian Energy Regulator, Transmission Annual Planning Report Guidelines, December 2018.
2 Separate to the publication of the TAPR document which occurs annually.

F.3 Development of daily demand profiles

Forecasts of the daily demand profiles for the days of annual maximum and minimum demands over the next 10 years were developed using VISION forecasting and planning (by Blunomy). These daily demand profiles are an estimate and should only be used as a guide. For further context and explanation of the methodology used to develop minimum and maximum demand profiles refer to Appendix D.2.

The 10-year forecasts of daily demand profiles that have been developed for the TAPR Templates include:

- 50% probability of exceedance (PoE) Maximum demand, MVA (TGCP008)
    - Where the megawatt (MW) transfer through the asset with emerging limitations reverses in direction, the megavolt amperes (MVA) is denoted a negative value
- Minimum demand, MVA (TGCP008)
    - Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011).

The maximum demand forecast on the minimum demand day (TGCP009) and the forecast daily demand profile on the minimum demand day (TGCP011) were determined from the minimum (annual) daily demand profiles.

Table F.1 Further Definitions for Specific Data Fields

Data Field	Definition
TGCP013 and TGTL008 Maximum load at risk per year	The load at risk takes into account both the network topology and aggregated outage and asset failure statistics for lines, transformers, and switching assets across the network. Where detailed project scopes and project requirements have not been determined, the aggregation of impacted loads were deemed at risk.
TGCP016 and TGTL011 Preferred investment - capital cost	The timing reflected for the estimated capital cost is the year of proposed project commissioning. RIT-Ts to identify the preferred option for implementation would typically commence three to five years prior to this date, relative to the complexity of the identified need, option analysis required and consideration of the necessary delivery timeframes to enable the identified need to be met. To assist non-network providers, RIT-Ts in the nearer term are identified in Table 5.4.
TGCP017 and TGTL012 Preferred investment - Annual operating cost	Powerlink has applied a standard 2% of the preferred investment capital cost to calculate indicative annual operating costs.
TGCP024 Historical connection point rating	Includes the summer and winter ratings for the past three years at the connection point. The historical connection point rating is based on the most limiting network component on Powerlink's network, in transferring power to a connection point. However lower downstream distribution connection point ratings could be more limiting than the connection point ratings on Powerlink's network.
TGCP026 Unplanned outages	Unplanned outage data relates to Powerlink's transmission network assets only. Forced and faulted outages are included in the data provided. Information to date is based on historical outage data.
TGPC028 and TGTL019 Annual economic cost of constraint	The annual economic cost of the constraint is the direct product of the annual expected unserved energy and the Value of Customer Reliability (VCR) related to the investment. It does not consider cost of safety risk or market impacts such as changes in the wholesale electricity cost or network losses.
TGTL005 Forecast 10-year asset rating	Asset rating is based on an enduring need for the asset's functionality and is assumed to be constant for the 10-year outlook period.
TGTL017 Historical line load trace	Due to the meshed nature of the transmission network and associated power transfers, the identification of load switching would be labour intensive and the results inconclusive. Therefore, the data provided does not highlight load switching events.

Appendix G Zone and grid section definitions

This appendix provides definitions of the 12 geographical zones and nine grid sections referenced in this Transmission Annual Planning Report (TAPR).

Tables G.1 and G.2 provide detailed definitions of zone and grid sections.

Table G.3 provides details of the name and type of generation connected to the transmission system is each zone.

Figure G.1 provides illustrations of the grid section definitions.

Table G.1 Zone definitions

Zone	Area covered
Far North	North of Guybal Munjan and Tully
Ross	North of King Creek and Bowen North, excluding the Far North and North West zones
North West	Mount Isa and Cloncurry
North	North of Broadsound and Dysart, excluding the Far North, North and Ross zones
Central West	South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone
Gladstone	South of Raglan, north of Gin Gin and east of Calvale
Wide Bay	Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie
Surat	West of Western Downs and south of Moura, excluding the Bulli zone
Bulli	Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Middle Ridge
South West	Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli zone
Moreton	South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone
Gold Coast	East of Greenbank, south of Coomera to the Queensland/New South Wales border

Table G.2 Grid Section Definitions (1)

Grid Section	Area covered
FNQ	Guybal Munjan into Chalumbin 275kV (2 circuits) Ross/Tully into Woree 275kV (1 circuit) Tully into El Arish 132kV (1 circuit)
NWQ	Flinders 500kV (2 circuits) to future 500kV substation in Ross area (2 circuits)
CQ-NQ	Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)
Gladstone	Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit)
CQ-SQ	Wurdong to Teebar Creek 275kV (1 circuit) Calliope River to Gin Gin/Woolooga 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)
Surat	Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit)
SWQ	Western Downs to Halys 275kV (1 circuit) Western Downs to Coopers Gap 275kV (1 circuit) Braemar (East) to Halys 275kV (2 circuits) Tummaville to Middle Ridge 330kV (2 circuits)
Tarong	Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)
Gold Coast	Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)

Note:

(1) The grid sections defined are as illustrated in Figure F.1. X into Y – the megawatt (MW) flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

Table G.3 Zone generation details

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
Far North	Barron Gorge			•				
	Kareeya			•				
	Koombooloomba			•				
	Mt Emerald					•		
	Kaban					•		
Ross	Townsville		•					
	Mt Stuart		•					
	Kidston (1)			•				
	Clare				•			
	Haughton				•			
	Ross River				•			
	Sun Metals				•			
	Invicta							•
North	Daydream				•			
	Hamilton				•			
	Hayman				•			
	Whitsunday				•			
	Rugby Run				•			
Central West	Callide B	•						
	Callide PP	•						
	Stanwell	•						
	Lilyvale				•			
	Moura				•			
	Broadsound (1)				•			
	Aldoga				•			
	Lotus Creek (1)					•		
	Clarke Creek					•		
	Boulder Creek (1)					•		
	Bouldercombe						•	
Gladstone	Gladstone	•						
	Yarwun		•					
Wide Bay	Woolooga Energy Park				•			
	Woolooga (1)						•	

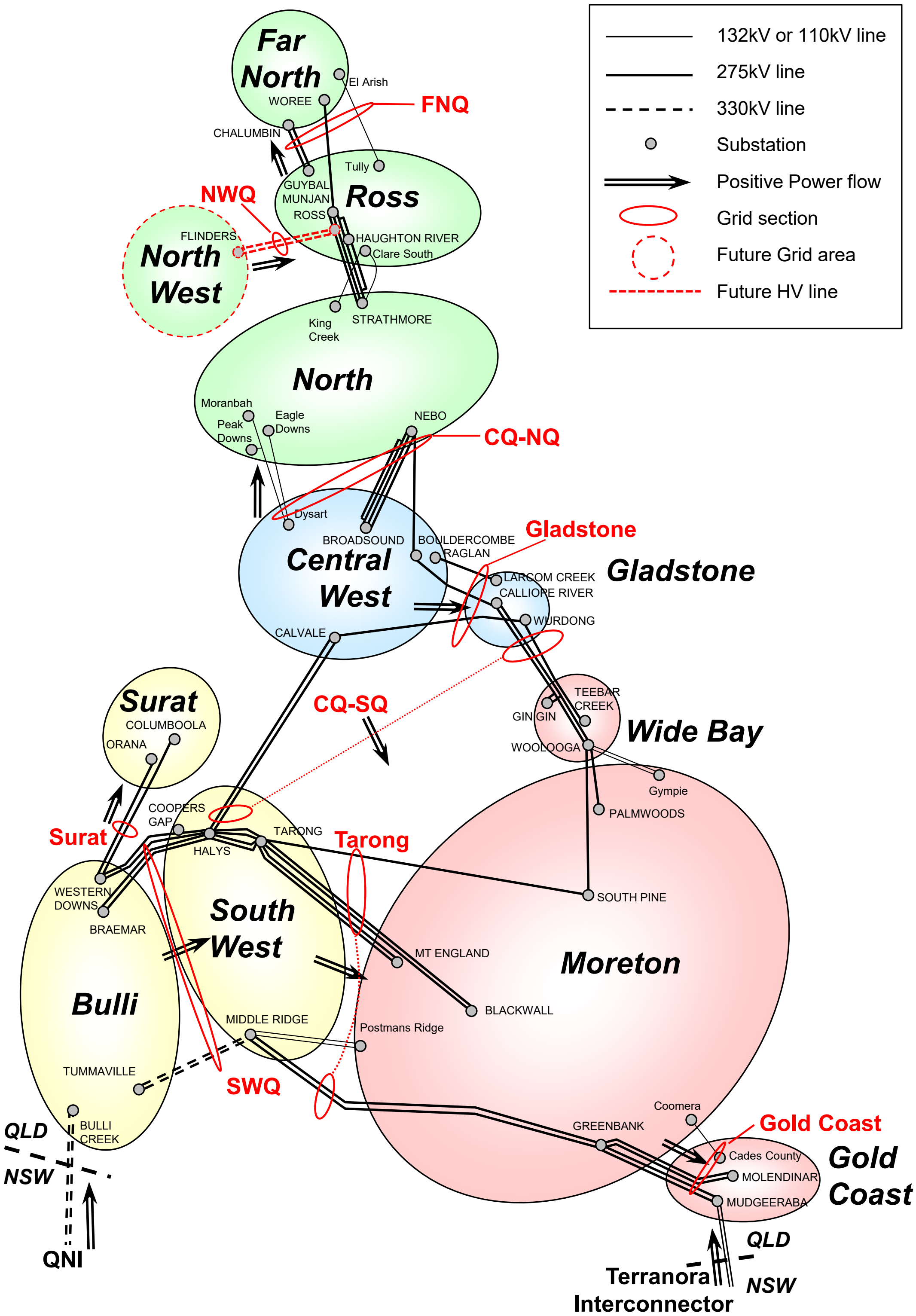
Table G.3: Zone generation details (*continued*)

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
Moreton	Swanbank E		•					
	Wivenhoe			•				
	Greenbank						•	
	Brendale						•	
	Supernode 1 & 2 (1)						•	
	Swanbank (1)						•	
South West	Tarong	•						
	Tarong North	•						
	Oakey		•					
	Wambo					•		
	Wambo 2 (1)					•		
	Coopers Gap					•		
	Tarong						•	
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
	Punchs Creek (1)				•		•	
	MacIntyre					•		
	Chinchilla						•	
	Ulinda Park						•	
	Western Downs						•	
Surat	Condamine		•					
	Columboola				•			
	Gangarri				•			
	Blue grass				•			
	Edenvale				•			
	Wandoan				•			
	Wandoan						•	

Note:

(1) Committed generation that is yet to begin production.

Figure G.1: Grid Section Legend



Appendix H Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland region of the National Electricity Market in its market dispatch systems.

Limit equations are continually under review to consider changing market and network conditions.

Interested parties should contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table H.1 Far North Queensland Grid Section Voltage Stability Equation

Measured Variable	Coefficient
Constant term (intercept)	597
Total MW generation at Mt Emerald Wind Farm	-0.55
Total MW generation at Kaban Wind Farm	-0.64
Total MW generation at Kareeya Power Station	-0.57
Total MW generation in Ross zone (1)	0.06
Total nominal MVAr of 132kV shunt capacitors online within nominated Cairns area locations (2)	0.38
Total nominal MVAr of 275kV shunt reactors online within nominated Cairns area locations (3)	-0.38
Total nominal MVAr of 132kV shunt reactors online within nominated Chalumbin area locations (4)	-0.36
Total nominal MVAr of 275kV shunt reactors online within nominated Chalumbin area locations (5)	-0.46
AEMO Constraint ID	Q^NIL_FNQ_8905

Notes:

(1) Ross generation term refers to summated active power generation at Mt Stuart, Townsville, Ross River Solar Farm, Sun Metals Solar Farm, Kidston Solar Farm, Hughenden Solar Farm, Clare Solar Farm, Haughton Solar Farm and Invicta Mill.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Cairns 132kV area comprise the following:

Innisfail 132kV	1 x 10MVAr
Edmonton 132kV	1 x 13MVAr
Woree 132kV	2 x 54MVAr

(3) The shunt reactor location, nominal sizes and quantities for the Cairns 275kV area comprise the following:

Woree 275kV	2 x 20.17MVAr, 1 x 42MVAr

(4) The shunt reactor location, nominal size and quantities for the Chalumbin 132kV and below area comprise the following:

Chalumbin tertiary	1 x 20.2MVAr

(5) The shunt reactor location, nominal sizes and quantities for the Chalumbin 275kV area comprise the following:

Chalumbin 275kV	2 x 29.4MVAr, 1 x 30MVAr

Table H.2 Central to North Queensland Grid Section Voltage Stability Equations

Measured Variable	Coefficient	
	Equation 1	Equation 2
	Feeder Contingency	Townsville Contingency
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	1.000
Total MW generation at Mt Stuart	0.092	0.136
Number of Mt Stuart units online [0 to 3]	22.447	14.513
Total MW northern VRE (2)	-1.00	-1.00
Total nominal MVAr shunt capacitors online within nominated Ross area locations (3)	0.453	0.440
Total nominal MVAr shunt reactors online within nominated Ross area locations (4)	-0.453	-0.440
Total nominal MVAr shunt capacitors online within nominated Strathmore area locations (5)	0.388	0.431
Total nominal MVAr shunt reactors online within nominated Strathmore area locations (6)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (7)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (8)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (9)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (9)	0.296	0.470
AEMO Constraint ID	Q^NIL_CN_FDR	Q^NIL_CN_GT

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) Northern VRE includes all solar farms and wind farms listed in Table G.3 in Appendix G in the Far North, Ross and North zones.

(3) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 132kV	1 x 50MVAr
Townsville South 132kV	2 x 50MVAr
Dan Gleeson 66kV	2 x 24MVAr
Garbutt 66kV	2 x 15MVAr

(4) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 275kV	2 x 84MVAr, 2 x 29.4MVAr

(5) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Newlands 132kV	1 x 25MVAr
Clare South 132kV	1 x 20MVAr
Collinsville North 132kV	1 x 20MVAr

(6) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Strathmore 275kV	1 x 84MVAr

(7) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Moranbah 132kV	1 x 52MVAr
Pioneer Valley 132kV	1 x 30MVAr
Kemmis 132kV	1 x 30MVAr
Dysart 132kV	2 x 25MVAr
Alligator Creek 132kV	1 x 20MVAr
Mackay 33kV	2 x 15MVAr

(8) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Nebo 275kV	1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr

(9) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:

Nebo 275kV	2 x 120MVAr

The following table describes limit equations for the Inverter-based Resources (IBRs) in north Queensland. The Boolean AND operation is applied to the system conditions across a row, if the expression yields a True value then the maximum capacity quoted for the farm in question becomes an argument to a MAX function, if False then zero (0) becomes the argument to the MAX function. The maximum capacity is the result of the MAX function.

Table H.3 North Queensland System Strength Equations

System Conditions								Maximum Capacity (%)				
Number of Stanwell units online	Number of Stanwell + Callide (1) units online	Number of CQ units online (2)	Number of Kareeya units online	NQ Load	Ross + FNQ Load	Haughton Synchronous Condenser Status	Clarke Creek Synchronous Condenser Status	Clarke Creek WF	Haughton SF	Kaban WF	Mt Emerald WF	Other NQ Plants
≥ 2	≥ 3	≥ 7	≥ 0	> 350	> 150	OFF	ON	100	0	60	60	100
≥ 2	≥ 3	≥ 7	≥ 0	> 250	> 100	OFF	ON	100	0	40	40	100
≥ 2	≥ 3	≥ 7	≥ 0	> 250	> 100	ON	ON	100	100	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	OFF	ON	100	50	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	ON	ON	100	100	100	100	100
≥ 1	≥ 4	≥ 6	≥ 2	> 350	> 150	OFF	ON	100	50	80	80	80
≥ 1	≥ 4	≥ 6	≥ 2	> 350	> 150	ON	ON	100	100	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	OFF	ON	100	N/A	100	100	Wind = 100 Solar = N/A
≥ 2	≥ 3	≥ 7	≥ 0	> 350	> 150	OFF	OFF	0	0	40	40	100
≥ 2	≥ 3	≥ 7	≥ 0	> 250	> 100	OFF	OFF	0	0	25	25	100
≥ 2	≥ 3	≥ 7	≥ 0	> 250	> 100	ON	OFF	0	100	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	OFF	OFF	0	50	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	ON	OFF	0	100	100	100	100
≥ 1	≥ 4	≥ 6	≥ 2	> 350	> 150	OFF	OFF	0	50	50	80	80
≥ 1	≥ 4	≥ 6	≥ 2	> 350	> 150	ON	OFF	0	100	100	100	100
≥ 2	≥ 3	≥ 7	≥ 2	> 350	> 150	OFF	OFF	0	N/A	100	100	Wind = 100 Solar = N/A
AEMO Constraint ID								Q_NIL_STRGTH_CKWF	Q_NIL_STRGTH_HAUSF	Q_NIL_STRGTH_KBWF	Q_NIL_STRGTH_MEWF	Various (3)

Notes:

(1) Refers to the total number of Callide B and Callide C units online.

(2) Refers to the number of Gladstone, Stanwell and Callide units online.

(3) Q_NIL_STRGTH_CLRSF, Q_NIL_STRGTH_COLSF, Q_NIL_STRGTH_DAYSF, Q_NIL_STRGTH_HAMSF, Q_NIL_STRGTH_HAYSF, Q_NIL_STRGTH_KEP, Q_NIL_STRGTH_KIDSF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_RUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

Table H.4 Central to South Queensland Grid Section Voltage Stability Equations

Measured Variable	Coefficient
Constant term (intercept)	1,015
Total MW generation at Gladstone 275kV and 132kV	0.1407
Number of Gladstone 275kV units on line [2 to 4]	57.5992
Number of Gladstone 132kV units on line [1 to 2]	89.2898
Total MW generation at Callide B and Callide C	0.0901
Number of Callide B units on line [0 to 2]	29.8537
Number of Callide C units on line [0 to 2]	63.4098
Total MW generation in southern Queensland (1)	0.0650
Number of 90MVAr capacitor banks available at Boyne Island [0 to 2]	51.1534
Number of 50MVAr capacitor banks available at Boyne Island [0 to 1]	25.5767
Number of 120MVAr capacitor banks available at Wurdong [0 to 3]	52.2609
Number of 50MVAr capacitor banks available at Gin Gin [0 to 1]	31.5525
Number of 120MVAr capacitor banks available at Woolooga [0 to 1]	47.7050
Number of 50MVAr capacitor banks available at Woolooga [0 to 2]	22.9875
Number of 120MVAr capacitor banks available at Palmwoods [0 to 1]	30.7759
Number of 50MVAr capacitor banks available at Palmwoods [0 to 4]	14.2253
Number of 120MVAr capacitor banks available at South Pine [0 to 4]	9.0315
Number of 50MVAr capacitor banks available at South Pine [0 to 4]	3.2522
Equation lower limit	1,550
Equation upper limit	2,100 (2)
AEMO Constraint ID	Q^^NIL_CS, Q:NIL_CS

Notes:

(1) Southern Queensland generation term refers to summated active power generation for all generators listed in Table G.3 in Appendix G in the Wide Bay, Moreton, South West, Bulli and Surat zones and Terranora Interconnector and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between Central and Southern Queensland areas.

Table H.5 Tarong Grid Section Voltage Stability Equations

Measured Variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys Contingency	Tarong-Blackwall Contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW in Surat, Bulli and South West and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	0.8625	0.7945
Total MW generation in Moreton	0.0517	0.0687
Active power transfer (MW) across Terranora Interconnector	0.0808	0.1287
Number of 200MVAr capacitor banks available (3)	7.6683	16.7396
Number of 120MVAr capacitor banks available (4)	4.6010	10.0438
Number of 50MVAr capacitor banks available (5)	1.9171	4.1849
Reactive to active demand percentage (6) (7)	2.9964	5.7927
Equation lower limit	3,200	3,200
AEMO Constraint ID	Q^^NIL_TR_CLHA	Q^^NIL_TR_TRBK

Notes:

(1) Equations 1 and 2 are offset by 100MW and 150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Surat, Bulli and South West generation term refers to summated active power generation for all generators listed in Table G.3 in Appendix G in the Surat, Bulli and South West zones and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(3) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 18 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 37 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage = $\frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector.

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table H.6 Gold Coast Grid Section Voltage Stability Equation

Measured Variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	20.0000
Active power transfer (MW) across Terranora Interconnector (3)	0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	Q^NIL_GC

Notes:

(1) Moreton to Gold Coast demand ratio = $\frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 16 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 33 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix I Indicative short circuit currents

Tables I.1 to I.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations. This appendix also shows the indicative System Strength Locational Factor (SSLF) calculated as per the Australian Energy Market Operator's (AEMO) System Strength Impact Assessment Guidelines[1]. An overview of system strength pricing can be found on Powerlink's website.

I.1 Indicative maximum short circuit currents

Tables I.1 to I.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2025/26, 2026/27 and 2027/28.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

Powerlink calculated the maximum short circuit currents using a system model:

- in which all generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with all model shunt elements removed.

The short circuit currents shown in tables I.1 to I.3 are based on generation shown in tables 6.1 and 6.2 (together with the more significant embedded non-scheduled generators) on the committed network development as forecast at the end of each calendar year. The tables also show the design rating of the Powerlink substation at each location. No assessment has been provided of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network; that is, all network elements are assumed to be in-service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create 'normally-open' points as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

I.2 Indicative minimum short circuit currents

Minimum short circuit currents are used to inform the capacity of the system to accommodate fluctuating loads and power electronic connected systems (including non-synchronous generators and static VAr compensators (SVC)). Minimum short circuit currents are also important in ensuring power quality and system stability standards are met and for ensuring the proper operation of protection systems.

Tables I.1 to I.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by taking the existing intact network and setting the synchronous generator dispatch to align with AEMO's assumptions for minimum three phase fault level as described in AEMO's 2024 System Strength Report. The short circuit current is calculated, using the sub-transient machine impedances, with the system intact and with individual outages of each significant network element.

The minimum short circuit current which results from these outages is reported.

The short circuit currents are calculated using the same methodology as the AEMO's assumptions.

These minimum short circuit currents are indicative only. The system strength available to new non-synchronous generators can only be assessed by a Full Impact Assessment using electromagnetic transient (EMT) modelling techniques.

[1] Australian Energy Market Operator, System Strength Impact Assessment Guidelines, Version 2.2, June 2024.

Table I.1 Indicative short circuit currents – Northern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26		Indicative maximum short circuit currents 2025/26		2026/27		2027/28		SSLF	Ref Node
				3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Aurumfield	275	40	1.2	1.1	1.0	4.1	4.5	4.11	4.6	4.1	4.6	1.1060	Ross 275kV
Bolingbroke	132	31.5	2.0	1.9	1.6	2.5	1.9	2.5	1.9	2.5	1.9	1.2135	Ross 275kV
Bowen North	132	31.5	2.1	0.7	0.9	3	3.2	3.0	3.2	3.0	3.2	1.1638	Ross 275kV
Cairns (2T)	132	31.5	3.1	0.5	0.6	6.8	9	6.8	8.9	6.8	8.9	1.0759	Ross 275kV
Cairns (3T)	132	31.5	3.1	0.5	0.5	6.8	8.9	6.8	8.9	6.8	8.9	1.0760	Ross 275kV
Cardwell	132	31.5	2.0	0.9	1.2	3.3	3.6	3.3	3.6	3.3	3.6	1.1438	Ross 275kV
Chalumbin	132	31.5	3.4	2.7	3.5	7.4	8.4	7.4	8.5	7.4	8.5	1.0790	Ross 275kV
Chalumbin	275	40	2.0	1.6	2.1	5.4	5.5	5.4	5.5	5.4	5.5	1.0453	Ross 275kV
Clare South	132	31.5	3.4	3.0	3.7	8.4	8.3	8.7	8.5	8.7	8.5	1.0687	Ross 275kV
Collinsville North	132	31.5	5.2	4.5	5.5	11.7	12	11.7	12.0	11.7	12.0	1.0432	Ross 275kV
Coppabella	132	31.5	2.2	1.5	1.8	3	3.4	3.0	3.4	3.0	3.4	1.1880	Ross 275kV
Crush Creek	275	40	3.5	3.0	4.0	10.9	12	10.8	11.9	10.8	11.9	1.0200	Ross 275kV
Dan Gleeson (1T)	132	31.5	4.2	3.8	5.0	13.3	13.5	13.3	13.6	13.3	13.6	1.0323	Ross 275kV
Dan Gleeson (2T)	132	31.5	4.2	3.8	5.0	13.3	13.6	13.3	13.6	13.3	13.6	1.0323	Ross 275kV
Eagle Downs	132	31.5	3.0	1.5	1.7	4.6	4.4	4.6	4.4	4.6	4.4	1.1297	Lilyvale 132kV
Edmonton	132	31.5	2.9	0.9	1.1	6.1	7.3	6.1	7.3	6.1	7.3	1.0835	Ross 275kV
El Arish	132	31.5	2.3	1.0	1.4	3.8	4.6	3.8	4.6	3.8	4.6	1.1213	Ross 275kV
Garbutt	132	31.5	3.9	1.7	2.0	11.4	11.2	11.4	11.2	11.4	11.2	1.0400	Ross 275kV
Goonyella Riverside	132	31.5	3.5	3.0	3.3	6	5.4	6.0	5.4	6.0	5.4	1.1090	Ross 275kV
Greenland	132	31.5	3.4	2.1	2.2	5.5	5.1	5.5	5.1	5.5	5.1	1.1165	Ross 275kV
Guybal Munjan	275	40	2.2	1.9	2.2	6.7	5.2	6.7	5.2	6.7	5.2	1.0266	Ross 275kV
Haughton River	275	40	2.7	2.1	2.7	8.5	8.6	8.5	8.6	8.5	8.6	1.0132	Ross 275kV

Table I.1 Indicative short circuit currents – Northern Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26		Indicative maximum short circuit currents 2025/26		2026/27		2027/28		SSLF	Ref Node
				3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Ingham South	132	31.5	2.0	1.1	1.3	3.5	3.5	3.5	3.5	3.5	3.5	1.1533	Ross 275kV
Innisfail	132	31.5	2.1	1.3	1.7	3.3	3.9	3.3	3.9	3.3	3.9	1.1434	Ross 275kV
Invicta	132	31.5	2.6	2.4	2.4	5.4	4.8	5.4	4.9	5.4	4.9	1.1055	Ross 275kV
Kamerunga (1T)	132	31.5	2.6	0.6	0.8	5	5.8	5.0	5.8	5.0	5.8	1.1061	Ross 275kV
Kamerunga (2T)	132	31.5	2.6	0.6	0.8	5	5.8	5.0	5.8	5.0	5.8	1.1061	Ross 275kV
Kareeya	132	31.5	3.2	2.4	3.0	6.2	6.8	6.2	6.8	6.2	6.8	1.0957	Ross 275kV
Kemmis	132	31.5	3.9	1.6	2.1	6.1	6.6	6.1	6.6	6.1	6.6	1.1014	Ross 275kV
King Creek	132	31.5	3.2	1.4	1.5	5.6	4.4	5.6	4.4	5.6	4.4	1.0887	Ross 275kV
Lake Ross	132	31.5	4.8	4.3	5.9	18.9	21	18.9	21.0	18.9	21.0	1.0187	Ross 275kV
Mackay	132	31.5	3.4	2.9	3.7	5.1	6.1	5.1	6.1	5.1	6.1	1.1190	Ross 275kV
Mackay Ports	132	31.5	2.6	1.6	2.1	3.5	4.1	3.5	4.1	3.5	4.1	1.1612	Ross 275kV
Mindi	132	31.5	3.5	3.3	2.8	4.9	3.7	4.9	3.7	4.9	3.7	1.1167	Ross 275kV
Moranbah	132	31.5	4.0	3.3	4.4	8	9.5	8.0	9.5	8.0	9.5	1.0977	Ross 275kV
Moranbah Plains	132	31.5	2.7	2.3	2.8	4.4	4.8	4.4	4.8	4.4	4.8	1.1540	Ross 275kV
Moranbah South	132	31.5	3.3	2.8	3.1	5.7	5.3	5.7	5.3	5.7	5.3	1.1216	Ross 275kV
Mt Mclaren	132	31.5	1.6	1.4	1.3	2.1	2.3	2.1	2.3	2.1	2.3	1.2713	Ross 275kV
Nebo	132	31.5	7.1	6.2	7.8	14.3	16.3	14.4	16.4	14.4	16.4	1.0525	Ross 275kV
Nebo	275	40	4.6	4.0	5.0	12.1	12.1	12.2	12.2	12.2	12.2	1.0370	Ross 275kV
Newlands	132	31.5	2.5	1.3	1.7	3.6	4	3.6	4.0	3.6	4.0	1.1490	Ross 275kV
North Goonyella	132	31.5	2.9	2.5	2.5	4.5	3.7	4.5	3.7	4.5	3.7	1.1330	Ross 275kV
Oonooie	132	31.5	2.4	1.5	2.0	3.1	3.7	3.1	3.7	3.1	3.7	1.1772	Ross 275kV
Peak Downs	132	31.5	2.8	2.1	2.3	4.2	3.7	4.2	3.7	4.2	3.7	1.1364	Lilyvale 132kV

Table I.1 Indicative short circuit currents – Northern Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26 3 phase (kA)	Indicative minimum N-1 2025/26 L – G (kA)	Indicative maximum short circuit currents 2025/26 3 phase (kA)	Indicative maximum short circuit currents 2025/26 L – G (kA)	Indicative maximum short circuit currents 2026/27 3 phase (kA)	Indicative maximum short circuit currents 2026/27 L – G (kA)	Indicative maximum short circuit currents 2027/28 3 phase (kA)	Indicative maximum short circuit currents 2027/28 L – G (kA)	SSLF	Ref Node
Pioneer Valley	132	31.5	4.1	3.6	4.5	6.6	7.5	6.6	7.6	6.6	7.6	1.0966	Ross 275kV
Proserpine	132	31.5	2.5	1.8	2.3	3.6	4.1	3.5	4.1	3.5	4.1	1.1375	Ross 275kV
Ross	132	31.5	4.8	4.4	5.9	19.6	21.9	19.6	21.9	19.6	21.9	1.0178	Ross 275kV
Ross	275	40	2.8	2.5	3.3	10.4	11.3	10.4	11.3	10.4	11.3	1.0000	Ross 275kV
Springlands	132	31.5	5.5	4.7	5.9	13	14.5	13.0	14.5	13.0	14.5	1.0384	Ross 275kV
Stony Creek	132	31.5	2.7	1.2	1.4	3.8	3.7	3.8	3.7	3.8	3.7	1.1343	Ross 275kV
Strathmore	132	31.5	5.6	4.8	6.1	13.4	15.4	13.4	15.4	13.4	15.4	1.0371	Ross 275kV
Strathmore	275	40	3.5	3.0	4.1	11	12.1	10.9	12.1	10.9	12.1	1.0197	Ross 275kV
Townsville PS	132	31.5	3.5	2.4	3.2	10.2	10.7	10.2	10.7	10.2	10.7	1.0535	Ross 275kV
Townsville East	132	31.5	3.9	1.6	1.8	13.4	12.8	13.5	12.9	13.5	12.9	1.0403	Ross 275kV
Townsville South	132	31.5	4.3	4.0	5.5	18.3	21.8	18.4	21.9	18.4	21.9	1.0305	Ross 275kV
Tully	132	31.5	2.8	1.5	1.8	5	5.7	5.0	5.7	5.0	5.7	1.0892	Ross 275kV
Tully South	275	40	1.7	1.2	1.4	3.9	3.7	3.9	3.7	3.9	3.7	1.0506	Ross 275kV
Tumoulin	275	40	1.8	1.3	1.6	4.5	4.9	4.5	4.9	4.5	4.9	1.0540	Ross 275kV
Turkinje	132	31.5	1.8	1.2	1.6	2.8	3.1	2.8	3.2	2.8	3.2	1.1932	Ross 275kV
Walkamin	275	40	1.7	1.4	1.8	4.3	4.8	4.3	4.9	4.3	4.9	1.0575	Ross 275kV
Wandoo	132	31.5	3.3	3.1	2.6	4.6	3.3	4.6	3.3	4.6	3.3	1.1241	Ross 275kV
Woree	132	31.5	3.2	2.7	3.9	7.1	9.6	7.1	9.6	7.1	9.6	1.0730	Ross 275kV
Woree	275	40	1.8	1.5	2.0	4.6	5.4	4.5	5.4	4.5	5.4	1.0530	Ross 275kV
Wotonga	132	31.5	3.5	1.7	2.2	6	7	6.0	7.0	6.0	7.0	1.1132	Ross 275kV
Yabulu South	132	31.5	3.8	3.3	4.0	11.4	10.8	11.4	10.8	11.4	10.8	1.0422	Ross 275kV

Table I.2 Indicative short circuit currents – Central Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26 3 phase (kA)	Indicative minimum N-1 2025/26 L – G (kA)	Indicative maximum short circuit currents 2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	2027/28 3 phase (kA)	2027/28 L – G (kA)	SSLF	Ref Node
Baralaba	132	31.5	3.4	2.1	2.0	4.4	3.8	4.4	3.8	4.4	3.8	1.1421	Lilyvale 132kV
Biloela	132	31.5	6.1	3.5	4.0	8.2	8.4	8.1	8.3	8.1	8.3	1.0889	Gin Gin 275kV
Blackwater	132	31.5	4.0	3.3	4.3	6	7.3	6.0	7.1	6.0	7.1	1.0480	Lilyvale 132kV
Bluff	132	31.5	2.6	2.3	2.6	3.5	4.3	3.5	4.3	3.5	4.3	1.1057	Lilyvale 132kV
Bouldercombe	132	31.5	10.2	6.3	7.8	15	17.2	15.1	17.3	15.1	17.3	1.0595	Gin Gin 275kV
Bouldercombe	275	40	10.1	8.6	10.2	22	20.8	22.5	21.3	22.5	21.3	1.0375	Gin Gin 275kV
Broadsound	275	40	6.0	4.9	6.7	16.1	18.7	16.5	17.7	16.5	17.7	1.0434	Lilyvale 132kV
Bundoora	132	31.5	5.2	4.4	5.2	9.5	9.2	9.5	9.2	9.5	9.2	1.0120	Lilyvale 132kV
Callemondah	132	31.5	16.0	6.7	7.1	22.4	24.9	22.5	25.0	22.5	25.0	1.0397	Gin Gin 275kV
Calliope River	132	40	17.5	14.2	18.0	25.2	30.2	25.4	30.3	25.4	30.3	1.0372	Gin Gin 275kV
Calliope River	275	40	10.4	8.7	11.3	22.1	25.1	22.6	25.6	22.6	25.6	1.0231	Gin Gin 275kV
Calvale	275	40	10.2	8.4	10.7	24.4	26.5	24.6	26.8	24.6	26.8	1.0379	Gin Gin 275kV
Calvale (1T)	132	31.5	6.6	2.8	3.1	8.6	9.4	8.6	9.3	8.6	9.3	1.0839	Gin Gin 275kV
Calvale (2T)	132	31.5	6.8	3.1	3.3	9	9.8	8.9	9.8	8.9	9.8	1.0822	Gin Gin 275kV
Duaringa	132	31.5	1.9	1.6	1.4	2.3	2.9	2.3	2.9	2.3	2.9	1.2140	Lilyvale 132kV
Dysart	132	31.5	3.2	1.9	2.4	4.8	5.4	4.8	5.4	4.8	5.4	1.1041	Lilyvale 132kV
Egans Hill	132	31.5	6.4	1.6	1.8	8.5	8.3	8.5	8.3	8.5	8.3	1.0851	Gin Gin 275kV
Gladstone PS	132	40	16.0	12.6	14.8	22.1	25.2	22.2	25.3	22.2	25.3	1.0411	Gin Gin 275kV
Gladstone PS	275	40	9.9	8.4	10.7	20.4	22.7	20.9	23.0	20.9	23.0	1.0241	Gin Gin 275kV
Gladstone South	132	31.5	12.3	9.6	11.1	16.4	17.3	16.4	17.3	16.4	17.3	1.0479	Gin Gin 275kV
Glencoe	275	40	-	-	-	-	-	9.4	9.5	9.4	9.5	-	-
Grantleigh	132	31.5	2.3	2.0	1.7	2.7	2.8	2.7	2.8	2.7	2.8	1.2084	Gin Gin 275kV
Gregory	132	31.5	5.7	4.7	6.0	10.6	11.8	10.6	11.8	10.6	11.8	1.0027	Lilyvale 132kV

Table I.2 Indicative short circuit currents – Central Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26 3 phase (kA)	Indicative minimum N-1 2025/26 L – G (kA)	Indicative maximum short circuit currents 2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	2027/28 3 phase (kA)	2027/28 L – G (kA)	SSLF	Ref Node
Larcom Creek	275	40	9.2	3.3	4.4	16.7	18.4	17.0	18.5	17.0	18.5	1.0296	Gin Gin 275kV
Larcom Creek	132	31.5	7.9	4.2	5.0	12.5	14.2	12.6	14.2	12.6	14.2	1.0597	Gin Gin 275kV
Lilyvale	132	31.5	5.9	4.8	6.3	11.2	13	11.3	13.0	11.3	13.0	1.0000	Lilyvale 132kV
Lilyvale	275	40	3.5	2.6	3.2	6.8	6.6	6.8	6.6	6.8	6.6	1.0216	Lilyvale 132kV
Moura	132	31.5	3.2	1.5	2.0	4.4	5.4	4.4	5.3	4.4	5.3	1.1545	Gin Gin 275kV
Muranu	275	40	-	-	-	-	-	14.9	14.2	14.9	14.2	-	-
Norwich Park	132	31.5	2.7	2.5	2.1	3.7	2.7	3.7	2.7	3.7	2.7	1.1087	Lilyvale 132kV
Pandoin	132	31.5	5.4	1.2	1.3	7	6.1	7.0	6.1	7.0	6.1	1.0971	Gin Gin 275kV
Raglan	275	40	7.7	4.3	3.8	12.5	11.1	12.6	11.2	12.6	11.2	1.0375	Gin Gin 275kV
Rockhampton (1T)	132	31.5	5.1	1.8	2.1	6.6	6.4	6.5	6.4	6.5	6.4	1.1022	Gin Gin 275kV
Rockhampton (5T)	132	31.5	5.0	1.8	2.1	6.3	6.2	6.3	6.2	6.3	6.2	1.1047	Gin Gin 275kV
Stanwell	275	40	10.8	9.0	11.2	25.2	26.2	25.8	27.3	25.8	27.3	1.0381	Gin Gin 275kV
Stanwell	132	31.5	4.8	3.7	4.3	6	6.5	6.0	6.5	6.0	6.5	1.1085	Gin Gin 275kV
Wurdong	275	40	9.4	6.4	6.4	17.3	17.1	17.7	17.3	17.7	17.3	1.0267	Gin Gin 275kV
Wycarbah	132	31.5	3.7	3.0	3.2	4.6	5.4	4.6	5.4	4.6	5.4	1.1346	Gin Gin 275kV
Yarwun	132	31.5	8.0	4.5	6.0	13.1	15	13.1	15.0	13.1	15.0	1.0617	Gin Gin 275kV

Table I.3 Indicative short circuit currents – Southern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26		Indicative maximum short circuit currents 2025/26		2026/27		2027/28		SSLF	Ref Node
				3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Abermain	110	31.5	12.9	10.4	11.7	22.2	25	22.0	24.7	22.0	24.7	1.0209	Greenbank 275kV
Abermain	275	40	8.1	6.3	7.0	19.7	19.8	20.2	20.1	20.2	20.1	1.0054	Greenbank 275kV
Algester	110	31.5	12.8	11.5	12.5	21.8	21.3	21.6	21.0	21.6	21.0	1.0207	Greenbank 275kV
Ashgrove West	110	31.5	12.1	9.3	10.4	19.8	20.6	19.5	20.3	19.6	20.3	1.0258	Greenbank 275kV
Banana Bridge	275	40	7.5	5.0	6.9	27.4	29	28.2	29.7	28.3	29.7	1.0007	Western Downs 275kV
Belmont	110	40	15.3	14.3	18.5	29.1	35.7	29.0	35.4	29.0	35.4	1.0128	Greenbank 275kV
Belmont	275	40	7.8	7.2	8.8	18.3	18.8	18.6	18.8	18.7	18.8	1.0051	Greenbank 275kV
Blackstone	110	40	14.5	13.3	15.2	26.5	28.8	26.4	28.6	26.4	28.6	1.0160	Greenbank 275kV
Blackstone	275	40	8.6	7.8	9.8	23.4	25.4	24.5	26.9	24.6	26.9	1.0017	Greenbank 275kV
Blackwall	275	40	9.9	8.3	10.5	24.8	26	25.5	26.3	25.6	26.3	1.0048	Greenbank 275kV
Blythdale	132	31.5	3.1	2.3	3.0	4.3	5.3	4.3	5.3	4.3	5.3	1.1113	Western Downs 275kV
Braemar	330	50	7.0	5.7	7.0	25.5	27.1	25.7	27.2	25.9	27.2	1.0086	Western Downs 275kV
Braemar (1T)	275	50	9.9	5.3	7.1	28.4	32.4	28.4	32.3	28.5	32.3	1.0118	Western Downs 275kV
Braemar (2T)	275	50	7.9	4.5	6.1	30.2	32.6	30.6	32.8	30.7	32.8	1.0048	Western Downs 275kV
Bulli Creek	330	50	6.8	6.2	6.9	20.2	15.6	20.6	15.7	21.1	15.7	1.0173	Western Downs 275kV
Bulli Creek	132	31.5	3.0	3.0	3.4	3.8	4.3	4.3	4.7	4.3	4.7	1.1368	Western Downs 275kV
Bundamba	110	31.5	11.1	7.6	7.8	17.7	16.9	17.5	16.6	17.5	16.6	1.0275	Greenbank 275kV
Cameby	132	31.5	4.7	3.6	4.1	9.1	8.5	9.2	8.6	9.2	8.6	1.0659	Western Downs 275kV
Chinchilla	132	31.5	3.8	3.0	3.5	6.5	7.9	6.5	7.9	6.5	7.9	1.0873	Western Downs 275kV
Clifford Creek	132	31.5	4.0	3.3	3.3	5.9	5.3	6.0	5.3	6.0	5.3	1.0810	Western Downs 275kV
Columboola	132	31.5	6.8	4.9	6.7	17.3	20.4	17.7	20.8	17.7	20.8	1.0370	Western Downs 275kV
Columboola	275	40	5.3	3.9	4.9	14.3	13.3	14.9	13.6	14.9	13.6	1.0125	Western Downs 275kV
Condabri Central	132	31.5	4.9	3.9	3.9	9.2	6.8	9.3	6.8	9.3	6.8	1.0609	Western Downs 275kV

Table I.3 Indicative short circuit currents – Southern Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26 3 phase (kA)	Indicative minimum N-1 2025/26 L – G (kA)	Indicative maximum short circuit currents 2025/26 3 phase (kA)	Indicative maximum short circuit currents 2025/26 L – G (kA)	Indicative maximum short circuit currents 2026/27 3 phase (kA)	Indicative maximum short circuit currents 2026/27 L – G (kA)	Indicative maximum short circuit currents 2027/28 3 phase (kA)	Indicative maximum short circuit currents 2027/28 L – G (kA)	SSLF	Ref Node
Condabri North	132	31.5	6.1	4.6	5.5	13.8	12.9	14.1	13.0	14.1	13.0	1.0438	Western Downs 275kV
Condabri South	132	31.5	4.1	3.3	2.9	6.6	4.5	6.7	4.5	6.7	4.5	1.0804	Western Downs 275kV
Coopers Gap	275	40	8.1	3.1	4.1	18.5	18.2	18.4	18.0	18.4	18.0	1.0158	Western Downs 275kV
Diamondy	275	40	7.9	6.7	5.6	15.1	11.5	15.4	12.9	15.4	12.9	1.0222	Western Downs 275kV
Dinoun South	132	31.5	4.4	3.6	4.1	6.8	7	6.9	7.1	6.9	7.1	1.0707	Western Downs 275kV
Eurombah	132	31.5	4.6	3.4	4.4	7.2	8.8	7.4	9.0	7.4	9.0	1.0672	Western Downs 275kV
Eurombah	275	40	2.7	1.2	1.4	4.7	4.8	4.8	4.9	4.8	4.9	1.0491	Western Downs 275kV
Fairview	132	31.5	3.0	2.5	3.3	4.1	5.1	4.1	5.2	4.1	5.2	1.1177	Western Downs 275kV
Fairview South	132	31.5	3.7	2.9	3.9	5.4	6.8	5.5	6.8	5.5	6.8	1.0895	Western Downs 275kV
Gin Gin	132	31.5	8.6	6.7	7.6	12.5	13.7	13.4	14.4	13.4	14.4	1.0185	Gin Gin 275kV
Gin Gin	275	40	6.1	4.3	4.5	9.6	9.1	10.2	9.4	10.2	9.4	1.0000	Gin Gin 275kV
Goodna	110	40	14.6	12.9	13.5	26.5	28.3	26.4	28.0	26.4	28.0	1.0164	Greenbank 275kV
Goodna	275	40	7.8	5.5	6.1	17.4	16.8	17.6	16.6	17.7	16.6	1.0078	Greenbank 275kV
Greenbank	275	50	8.5	7.7	10.0	22.7	25.2	23.5	25.9	23.6	25.9	1.0000	Greenbank 275kV
Halys	275	50	12.3	9.6	11.9	35.7	30.9	36.0	31.1	36.1	31.1	1.0129	Western Downs 275kV
Kumbarilla Park	132	31.5	7.6	4.3	5.2	11.7	13.4	11.5	13.2	11.5	13.2	1.0431	Western Downs 275kV
Kumbarilla Park	275	40	6.7	1.4	1.6	17.1	16.1	17.0	16.0	17.1	16.0	1.0173	Western Downs 275kV
Loganlea	110	40	13.3	12.0	14.9	23.5	28	23.3	27.7	23.4	27.7	1.0170	Greenbank 275kV
Loganlea	275	40	7.3	6.0	7.1	16	16.2	16.2	16.2	16.3	16.2	1.0059	Greenbank 275kV
Middle Ridge	110	40	10.6	8.8	11.4	22.1	26	21.8	25.6	21.9	25.6	1.0350	Greenbank 275kV
Middle Ridge	275	40	7.6	6.7	8.2	20.2	19.8	20.2	19.7	20.5	19.7	1.0136	Greenbank 275kV
Middle Ridge (4T)	330	50	5.8	3.6	3.6	14.1	13.3	14.0	13.2	14.2	13.2	1.0244	Western Downs 275kV
Middle Ridge (5T)	330	50	5.9	3.6	3.5	14.5	13.8	14.5	13.6	14.7	13.6	1.0240	Western Downs 275kV

Table I.3 Indicative short circuit currents – Southern Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26		Indicative maximum short circuit currents 2025/26		2026/27		2027/28		SSLF	Ref Node
				3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Millmerran	330	50	6.3	5.9	7.4	21.6	22.8	21.7	22.9	22.7	22.9	1.0200	Western Downs 275kV
MISS	330	50	5.2	4.5	5.8	15.3	16.6	15.2	16.5	15.6	16.5	1.0265	Western Downs 275kV
Molendinar	110	31.5	11.9	10.2	13.4	19.9	25	19.7	24.7	19.7	24.7	1.0199	Greenbank 275kV
Molendinar (1T)	275	40	5.0	2.1	2.4	8.5	8.2	8.5	8.1	8.5	8.1	1.0175	Greenbank 275kV
Molendinar (2T)	275	40	5.0	2.1	2.4	8.5	8.2	8.5	8.1	8.5	8.1	1.0176	Greenbank 275kV
Mt England	275	40	9.6	8.1	9.9	24.9	24.5	25.4	24.5	25.4	24.5	1.0072	Greenbank 275kV
Mudgeeraba	110	31.5	11.0	10.0	12.6	17.8	21.5	17.6	21.2	17.7	21.2	1.0233	Greenbank 275kV
Mudgeeraba	275	40	5.4	4.3	4.7	9.6	8.8	9.6	8.7	9.6	8.7	1.0143	Greenbank 275kV
Murarrie	110	40	13.9	12.7	16.0	24.7	29.6	24.5	29.2	24.5	29.2	1.0164	Greenbank 275kV
Murarrie (1T)	275	40	6.8	2.3	2.6	14	13.7	14.1	13.6	14.1	13.6	1.0092	Greenbank 275kV
Murarrie (2T)	275	40	6.8	2.3	2.6	14	13.8	14.0	13.7	14.1	13.7	1.0092	Greenbank 275kV
Oakey	110	31.5	4.9	1.3	1.4	10.3	10.2	10.2	10.1	10.2	10.1	1.0935	Greenbank 275kV
Oakey PS	110	31.5	5.1	3.7	4.9	11.5	12.6	11.4	12.5	11.4	12.5	1.0882	Greenbank 275kV
Orana	275	40	6.0	3.0	3.8	16.9	16.2	17.3	16.4	17.3	16.4	1.0073	Western Downs 275kV
Palmwoods	132	31.5	9.2	6.8	8.7	13.7	16.4	13.8	16.4	13.8	16.4	1.0403	Greenbank 275kV
Palmwoods	275	40	5.6	3.4	4.1	9	9.3	9.2	9.4	9.2	9.4	1.0299	Greenbank 275kV
Palmwoods (7T)	110	31.5	5.7	2.6	2.3	7.4	7.6	7.3	7.5	7.3	7.5	1.0834	Greenbank 275kV
Palmwoods (8T)	110	31.5	5.7	2.6	2.3	7.4	7.6	7.3	7.5	7.3	7.5	1.0834	Greenbank 275kV
Punchs Creek	330	50	-	-	-	-	-	-	-	20.3	21.5	-	-
Redbank Plains	110	31.5	13.0	9.5	10.1	22.1	21.1	21.9	20.8	21.9	20.8	1.0207	Greenbank 275kV
Richlands	110	31.5	13.2	11.0	12.6	22.7	23.2	22.5	22.9	22.5	22.9	1.0202	Greenbank 275kV
Rocklea	110	40	14.6	12.9	15.6	26.1	29.9	25.9	29.5	26.0	29.5	1.0180	Greenbank 275kV
Rocklea (1T)	275	40	7.0	2.3	2.6	14	12.8	14.0	12.7	14.0	12.7	1.0122	Greenbank 275kV

Table I.3 Indicative short circuit currents – Southern Queensland *(continued)*

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum N-1 2025/26		Indicative maximum short circuit currents 2025/26		2026/27		2027/28		SSLF	Ref Node
				3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Rocklea (2T)	275	40	5.4	2.3	2.6	9.2	8.7	9.1	8.6	9.1	8.6	1.0235	Greenbank 275kV
Runcorn	110	31.5	11.8	8.6	9.7	19.4	19.6	19.2	19.2	19.2	19.2	1.0237	Greenbank 275kV
South Pine	275	40	9.3	7.9	10.6	21.6	25.4	22.0	25.7	22.0	25.7	1.0099	Greenbank 275kV
South Pine (East)	110	40	13.6	11.5	15.5	24	31	23.6	32.5	23.6	32.5	1.0253	Greenbank 275kV
South Pine (West)	110	40	12.9	10.1	11.7	21.3	24.6	21.1	24.2	21.1	24.2	1.0249	Greenbank 275kV
Sumner	110	31.5	12.8	9.1	9.9	21.4	21.2	21.2	20.8	21.2	20.8	1.0226	Greenbank 275kV
Swanbank E	275	40	8.5	7.3	8.9	23	24.8	24.1	26.1	24.1	26.1	1.0017	Greenbank 275kV
Tangkam	110	31.5	6.0	4.2	5.1	13.8	12.6	13.7	12.5	13.7	12.5	1.0729	Greenbank 275kV
Tarong	66	31.5	12.3	7.0	7.7	15.5	16.6	15.1	16.2	15.1	16.2	1.0642	Greenbank 275kV
Tarong	275	50	11.9	9.5	12.7	37.4	39.5	37.6	39.4	37.7	39.4	1.0111	Greenbank 275kV
Teebar Creek	132	31.5	7.2	4.5	5.3	10.1	11.1	11.6	13.1	11.6	13.1	1.0469	Gin Gin 275kV
Teebar Creek	275	40	4.9	2.3	2.6	7.5	7.2	9.0	9.9	9.0	9.9	1.0319	Gin Gin 275kV
Tennyson	110	31.5	10.8	1.8	1.9	16.7	16.7	16.5	16.4	16.5	16.4	1.0309	Greenbank 275kV
Tummaville	330	50	6.2	5.8	7.1	20.2	19	20.3	19.0	21.2	19.0	1.0210	Western Downs 275kV
Upper Kedron	110	40	13.1	11.4	11.8	22.1	19.8	21.9	19.5	21.9	19.5	1.0227	Greenbank 275kV
Wandoan South	132	31.5	5.5	4.2	5.8	10.2	13.1	10.6	13.5	10.6	13.5	1.0512	Western Downs 275kV
Wandoan South	275	40	3.8	3.0	4.0	8.2	9.3	8.9	9.8	8.9	9.8	1.0272	Western Downs 275kV
West Darra	110	31.5	14.5	13.3	13.9	26	24.6	25.8	24.3	25.8	24.3	1.0173	Greenbank 275kV
Western Downs	275	50	7.7	5.1	7.1	29.8	32.4	30.8	33.4	30.9	33.4	1.0000	Western Downs 275kV
Woolooga	132	31.5	9.0	7.1	9.2	14.5	18	16.0	19.8	16.0	19.8	1.0394	Gin Gin 275kV
Woolooga	275	40	6.4	5.4	6.8	10.8	12.4	12.1	13.6	12.1	13.6	1.0223	Gin Gin 275kV
Yuleba North	132	31.5	5.0	3.9	4.9	8.2	9.9	8.4	10.1	8.4	10.1	1.0590	Western Downs 275kV
Yuleba North	275	40	3.4	2.7	3.5	6.5	7.1	6.9	7.3	6.9	7.3	1.0349	Western Downs 275kV

Appendix J Designated Network Assets

This appendix provides information about which parts of Powerlink's transmission network are Designated Network Assets (DNAs) and the owners of DNAs.

J.1 Introduction

In July 2021, the Australian Energy Market Commission (AEMC) made the Connection to Dedicated Network Assets Rule. The rule change introduced the concept of a Designated Network Asset (DNA) into the National Electricity Rules (NER). Under the new rule, new transmission lines with a total route length in excess of 30 kilometres (km) are adopted as part of the shared transmission network and deemed to be a DNA under the NER.

Powerlink has two DNAs:

- MacIntyre DNA
- Western Downs DNA

This appendix includes information about which parts of the network are DNAs and the identities of the owners of those DNAs[1].

J.2 MacIntyre DNA

Powerlink is the owner of the MacIntyre DNA.

Table J.1 identifies the components of the MacIntyre DNA.

Table J.1 Main components of the MacIntyre DNA and tenure arrangements

No	Asset Component	Description	Tenure
1	Network Interface Assets	Cut-in-works and related assets from the Identified User Shared Assets (IUSA) to the existing Shared Transmission Network	Easement
2	IUSA	330kV Tummaville Switching Station	Freehold
3	DNA Component 1	330kV Transmission line between Tummaville Switching Station and MacIntyre Intermediate Switching Station and associated easements	Easement
4	DNA Component 2	330kV MacIntyre Intermediate Switching Station and associated access easement	Freehold (switching station) and easement

More information on the MacIntyre DNA is available on Powerlink's website.

J.3 Western Downs DNA

Powerlink is the owner of the Western Downs DNA.

Table J.2 identifies the components of the Western Downs DNA.

Table J.2 Main components of the Western Downs DNA and tenure arrangements

No	Asset Component	Description	Tenure
1	DNA Component 1	48.5km of 275kV double circuit transmission line between Halys Substation to the Diamondy Switching Station and associated easements.	Easement
2	DNA Component 2	275kV Diamondy Switching Station and associated access easement.	Freehold (switching station) and easement

More information on the Western Downs DNA is available on Powerlink's website.

[1] National Electricity Rules, clause 5.12.2(c)(6B).

Appendix K Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
AI	Artificial Intelligence
AIS	Air Insulated Switchgear
ARR	Asset Reinvestment Review
BSL	Boyne Smelters Limited
BESS	Battery Energy Storage System
BOM	Bureau of Meteorology
CAA	Connection and Access Agreement
CBD	Central Business District
CER	Consumer Energy Resources
CQ	Central Queensland
CQ-SQ	Central Queensland to South Queensland
CQ-NQ	Central Queensland to North Queensland
DCA	Dedicated Connection Assets
DER	Distributed Energy Resources
DNA	Designated Network Assets
DNSP	Distribution Network Service Provider
DSM	Demand side management
EAP	Energy Advisory Panel
ECMC	Energy and Climate Change Ministerial Council
ECMWF	European Centre for Medium-Range Weather Forecasts
ECS	Emergency Control Scheme
EFCS	Emergency Frequency Control Schemes
EJPC	Executive Joint Planning Committee
ENA	Energy Networks Australia
EMT	Electromagnetic Transient
EOI	Expression of interest
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
EUSE	expected unserved energy
FIA	Full Impact Assessment

FNQ	Far North Queensland
FRG	Forecasting Reference Group
FTPWG	Future Transition Points Working Group
FY	Financial Year
GPSRR	General Power System Risk Review
GWh	Gigawatt hours
HTC	High Temperature Conductor
HV	High Voltage
IBR	Inverter-based Resources
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
JPC	Joint Planning Committee
kA	Kiloampere
kV	Kilovolts
kW	Kilowatt
LEIP	Lansdown Eco-Industrial Precinct
LTTW	Lightning Trip Time Window
MLF	Marginal Loss Factors
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
MWs	Megawatt seconds
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NGNO	Next Generation Network Operations
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Providers
NSW	New South Wales
NQ	North Queensland
NWMP	North West Minerals Province
OFGS	Over Frequency Generation Shedding
OIP	Optimal Infrastructure Pathway

Appendix I Glossary *(continued)*

OTPWG	Operational Transition Points Working Group
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PHES	Pumped Hydro Energy Storage
PoE	Probability of Exceedance
PSCR	Project Specification Consultation Report
PSMRG	Power System Modelling Reference Group
PTI	Priority Transmission Investment
PV	Photovoltaic
QAL	Queensland Alumina Limited
QHES	Queensland Household Energy Survey
QIC	Queensland Investment Corporation
QNI	Queensland to New South Wales Interconnector
RAS	Remedial Action Scheme
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RSAS	Reliability and Security Ancillary Service
RWG	Regulatory Working Group
SQ	Southern Queensland
SEQ	South East Queensland
SPS	Special Protection Scheme
SSIAG	System Strength Impact Assessment Guidelines
SSLF	System Strength Locational Factor
SSSP	System Strength Service Provider
SVC	Static VAr Compensator
SWQ	South West Queensland
TAPR	Transmission Annual Planning Report
TGCP	TAPR Guideline Connection Point
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable Renewable Energy
VTL	Virtual Transmission Line
WAMPAC	Wide Area Monitoring Protection and Control

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